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The Environmental Implications of Power Sector Reform in Developing Countries

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Final Report

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United States Agency for International Development
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FOREWORD

The 1990s has seen a dramatic shift away from the state-owned monopoly model towards corporatized, privatized, and restructured power sectors in developing countries. While most developing countries (and development agencies such as USAID) have embraced sector reform as a net benefit for sustainable development, little critical attention has been paid to the environmental implications of the reforms undertaken.

The clear presumption has been that market discipline will lead to improved environmental performance, that the "invisible hand" will also be a "green" hand. While this may be true as economies shift from inefficient public sector management to private delivery mechanisms, it is not clear that market forces will always reward the environmentally preferable choice. Absent appropriate regulatory or price incentives (such as including externalities), market forces may reward investments that maximize short-run profits, rather than those that optimize life cycle costs and benefits. Investments in energy efficiency, renewable energy, hydropower and nuclear power, for example, all stand to suffer when short-run marginal costs determine investment decisions.

The purpose of this report to examine the relationship between specific reforms and decisions that affect the environment. To do so, it disaggregates the different reforms and traces the ways that each one affects the behavior of actors in the power sector.

Because the package of reforms and the reform process that each country implements is unique, the net effect that reforms have on environmental performance is country-specific. Still, the reform packages that most developing countries adopt are likely to *improve* the environmental performance of the sector which, in its non-reformed state, is often dismal.

Although a few countries have made their reforms long enough ago to get some post-reform data, in most cases, power sector reform is still a work in progress. Consequently, statistical approaches to answering the basic question were not feasible. This report broadens the debate and clarifies the issues, but is by no means the last word. As the post-reform evidence accumulates around the globe, definitive trends may emerge from which to revisit the relationships discussed in this report.

Equally important are the report's answers to the question of what, if anything, must be done by in-country reformers or development assistance organizations. One thing is clear: Regardless of their environmental implications, reforms will move ahead. If power sector reformers and other stakeholders are at least sensitized to their potential environmental implications, direct and indirect, the reform process can be guided in directions so that the outcome maximizes

environmental benefits and minimizes any adverse effects. This report will hopefully stimulate in-country discussion and consideration of interventions at key points in the reform process to ensure environmental progress.

Jeff Seabright
Director, Office of Energy, Environment & Technology

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DEDICATION TO MOLLY KUX

This report is dedicated to Molly Kux, who was a tireless pioneer on environment and development at USAID. Molly never missed an opportunity to press her colleagues in the Office of Energy on the environmental implications of our support for power sector privatization. And she was not satisfied with the simplistic reply that resource use is more efficient when managed by the private sector. This report seeks to begin to answer the central question Molly posed to us all.

ACRONYMS

ADB	Asian Development Bank
BOO	build-own-operate
BOOT	build-own-operate-transfer
Btu	British thermal unit
CEE	Central and Eastern Europe
CEGB	Central Electricity Generating Board of the UK
CFD	contracts for differences
CO_2	carbon dioxide
CPCB	Central Pollution Control Board of India
DSM	demand-side management
EC	European Community
ENRE	Ente Nacional Regulador de Electricidad (Argentina's independent regulatory agency)
EIA	environmental impact assessment
ESCO	energy service company
EST	Energy Saving Trust (UK)
EU	European Union
FGD	flue gas desulfurization
GDP	gross domestic product
GNP	gross national product
GW	gigawatt
IPP	independent power project
IRP	integrated resource planning
ISO	independent system operator
kWh	kilowatt-hour
LNG	liquified natural gas
MEM	Mercado Electrico Mayorista (Argentina's wholesale electric spot market)

MoEF	Ministry of Environment and Forests of India
MW	megawatt
NFFO	Non-Fossil Fuel Obligation (UK)
NGO	non-government organization
NO_x	nitrous oxides
O&M	operations and maintenance
OECD	Organization for Economic Cooperation and Development
OFFER	Office of Electricity Regulation of the UK
OERC	Orissa Electricity Regulatory Commission
OSEB	Orissa State Electricity Board
PPA	power purchase agreement
R&D	research and development
REC	Regional Electricity Companies of the UK
SEB	State Electricity Boards of India
SO_2	sulfur dioxide
SPCB	State Pollution Control Board of India
T&D	transmission and distribution
TWh	terawatt-hour
USAID	U.S. Agency for International Development
VAT	value added tax

EXECUTIVE SUMMARY

In most non-OECD[1] countries, the provision of electricity services has until recently been a government function. Access to electricity has often been considered a "right" and full electrification a policy goal. Government utilities in these countries have been experiencing severe managerial and financial problems as the demand for power escalates and service quality declines.

To address these issues, many governments have initiated power sector reforms. Reforms have been undertaken to streamline management and operations, introduce economic efficiency, stimulate private investment, and reduce deficits and international debt. Taking as models the experience of countries that have already reformed their power sectors, policy makers have usually decided on a series of reforms to be implemented over a period of years. These changes are typically preceded by enabling legislation and accompanied by the creation of an independent regulatory agency.

There are four basic types of reform:

- ***Commercialization:*** a change in management and operation of a state-owned utility to make it similar to a commercial enterprise and subject to corporate laws. Accounting functions are also separated for generation, transmission, and distribution services, and made transparent.

- ***Privatization:*** a change from public to private ownership of existing power sector assets. This is often preceded by private development of new power plants.

- ***Restructuring:*** a change in the structure of the power sector. A common version of this reform is unbundling, in which the vertically integrated utility is separated into legally and functionally distinct firms providing separate generation, transmission, distribution, and retail services.

- ***Competition:*** a change in the rules by which the power sector operates. Under wholesale competition, multiple generators compete to sell power to the grid. Under retail competition, several suppliers compete to supply power to end users.

[1] The OECD consists of North America, Western Europe, Japan, Australia, and New Zealand.

All of these reforms have potentially profound consequences for environmental sustainability. The purpose of this report is to help policy makers better understand the interactions between reform and environmental quality so that environmental priorities can be integrated into the power sector reform process. To bound the analysis, this study focuses on air emissions. It reviews published literature, evaluates the experience of three countries at various stages of reform (the United Kingdom, Argentina, and India), and presents the results of a modeling exercise showing the effects of various reforms on air emissions.

ES.1 ENVIRONMENTAL IMPLICATIONS OF MAJOR TYPES OF REFORMS

Power sector decisions that affect environmental performance include the choice of fuel and technology for new power plants, operation and maintenance practices for the sector, investment in transmission and distribution (T&D) equipment, tariff structure, promotion of customer end-use efficiency and load management, and investment in commercializing new power system technologies.

Power Generation. In countries with rapidly growing power demand, the choice of fuel and technology for new generation probably has a stronger impact on local air pollutants and carbon dioxide emissions than anything else. Whether this influence is positive or negative depends on the particular characteristics of a country's power sector (generation mix, emissions standards and enforcement, etc.). For example, replacing a coal with hydropower, other renewable resources, or gas sharply reduces air emissions.

Supply-Side Efficiency. Energy losses from T&D systems contribute to air emissions. This type of energy loss can be reduced by reforms that stimulate investment in T&D infrastructure, improve T&D operation, or reduce theft. Among case study countries, operations and maintenance improvements in the power system in Argentina have played a significant role in reducing fuel consumption; they promise to do the same in India.

End-Use Efficiency. Air emissions are directly and significantly influenced by electricity load curves. Load curves are determined by customer lifestyles and economic activity, electricity tariff structures, and end-use equipment efficiency. Utility programs can change these load curves by shifting customer demand among periods or by making energy-using equipment more efficient. Utility-sponsored energy efficiency services, however, have not been common among case study countries (or others) prior to reforms.

When competition is introduced, price usually becomes the key factor in determining a customer's choice of electricity supplier. Immediately following the introduction of competition, there is usually a decline in end-use energy efficiency activities. In the UK, utilities were required to impose a fee on customers in order to assure continued support for energy efficiency activities

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during this period. In all three case study countries, however, there is little post-reform utility-sponsored activity to promote efficiency among smaller end-users.

Electricity Price Signals. Tariff structures create the price signals that influence customers' use of electricity. Tariffs that accurately reflect the cost of providing service (which varies by location and time of day) provide appropriate price signals to customers. These signals, in turn, influence patterns of demand and thus generation emissions. Customers' responsiveness to price signals also depends upon whether or not they expect their electricity bills will be collected.

Reforms affect price signals in several ways. Consumer prices increase when subsidies are eliminated as a result of privatization. On the other hand, introducing wholesale and retail competition is likely to reduce prices where subsidies have not existed. Unbundling the sector affects the way customers' bills will look, with generation, transmission, distribution, and marketing costs all shown separately. Whether prices go up or down in the period after reform depends on which of these effects dominate in a specific country.

Environmental Controls. Power plant emissions standards and their enforcement are a key determinant of environmental performance. A clear assignment of authority, adequate funding mechanisms, and institutional capacity among regulatory bodies are all prerequisites for implementing and enforcing environmental legislation. In the UK and Argentina, environmental policy was revised as reforms were introduced. Although tougher standards were enacted, enforcement was not necessarily strengthened.

Exhibit ES-1 summarizes how different reforms affect generation choice and supply side efficiency and the extent to which they reduce end-use consumption.

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Exhibit ES-1
Summary Implications of Power Sector Reforms on Environmental Performance
(⇑ = environmentally favorable, ⇓ = unfavorable, ⇕ = depends on implementation)

REFORM	EFFECTS ON GENERATION TECHNOLOGY AND SUPPLY-SIDE EFFICIENCY	EFFECTS ON END-USE EFFICIENCY
Commercialization	Better cost accounting reduces waste ⇑ Improved operation of generation, transmission, and distribution systems reduces energy losses ⇑	Customer efficiency incentives strengthened by tariff reform and improved revenue recovery ⇑
Privatization	Separation from government allows independent regulation of environmental performance ⇑ Generating capacity increased by private power development ⇓ which reduces diesel self-generation ⇑ Off-grid renewable generation boosted by removing subsidies for grid extension ⇑ Generation, transmission, and distribution assets upgraded by private capital ⇑	Customer efficiency incentives improved by stronger attention to cost recovery and subsidy removal ⇑ Reduced cost-effectiveness of utility end use efficiency investments due to higher discount rate ⇓
Unbundling	Deployment of distributed generation depends on ability to capture system-wide benefits ⇕ Equal access to transmission system by renewable power projects depends on contract terms ⇕ Profit motive of transmission and distribution providers reduces energy losses ⇑ Nonrenewable generation favored by power purchase terms ⇓	Customer incentives to invest in efficiency improvements depend on how upstream costs are reflected in bills ⇕ Retail supplier investment in efficiency improvement depends on treatment of capacity, fuel, transmission and distribution costs ⇕
Wholesale Competition	Low capital cost, dispatchable generation rather than renewable generation favored by short-term markets ⇓ Highly-efficient fossil generation technologies favored by short-term markets ⇑	Customer efficiency incentives weakened when competition lowers prices and makes future economic benefits less certain ⇓

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REFORM	EFFECTS ON GENERATION TECHNOLOGY AND SUPPLY-SIDE EFFICIENCY	EFFECTS ON END-USE EFFICIENCY
Retail Competition	Low capital cost generation favored by retail competition ⇓ Reduced incentives to invest in R&D on environmentally-superior technologies ⇓	Rate cap regulation creates incentive to maximize kWh sales ⇓ Customer efficiency incentives weakened by ability to switch to lower cost supplier ⇓ DSM services may be offered to stand out from competitors ⇑

ES.2 LESSONS FOR DEVELOPING COUNTRIES

The experiences of the United Kingdom, Argentina, and India, as examined in this report, show the importance not only of the power sector reforms themselves but also of the context in which the reforms take place. For example, protection of the UK's coal industry and prohibitions on gas-fired generation (despite plentiful gas supplies) were both relaxed at the time of the UK's power sector reforms, leading to a "dash for gas." These factors make the UK's reform uniquely successful in reducing air emissions; most developing countries do not share these characteristics.

When the environmental performance of a publicly owned and operated power sector is poor, reforms generally bring improvement. Still, environmental considerations are at best secondary when policy makers are deciding which reforms to adopt and how to implement them. Moreover, many developing countries lack the capacity for developing and enforcing environmental regulations.

Of the major types of reform, some have both economic and environmental benefits, while others represent tradeoffs. With some exceptions, the environmental benefits of commercialization, privatization, and regulation appear to be stronger then those of unbundling and the introduction of competition.

Some important conclusions:

- Commercialization reforms have positive environmental implications with little downside risk.
- Privatizing the power sector's assets is more likely to lead to improvements in environmental performance if requirements have been specified in advance.

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- Establishing an independent regulator can locate in one agency responsibility for: eliminating tariff subsidies, licensing new facilities, overseeing competitive markets, promoting least cost approaches to system expansion, and balancing national policy objectives such as environmental protection against the financial health of the sector.

- The environmental implications of allowing privately developed new generating capacity and of introducing wholesale competition depend on the types of generation chosen by developers.

- Retail competition appears to be a net negative effect on environmental performance.

- The liberalization of fuel supply sectors generally allows more environmentally friendly fuels to be used for generation.

ES.3 RECOMMENDATIONS

The power sector reform process offers a timely opportunity to promote positive environmental change. Because the sector is already in flux, it may be easier to address environmental issues at this time. Moreover, designing positive environmental incentives at the beginning of the process is more cost-effective than correcting problems later. Each country's reform process and unique political environment will determine the feasibility of specific interventions. Some of the measures proposed in the report to promote environmental protection are as follows:

- *Establish an independent regulatory body prior to reforms whose authority includes oversight over power sector decisions that affect environmental performance.*

- *Include environmental criteria when weighing bids for selling power sector assets and allocate part of the sale proceeds to funding renewables and energy efficiency.*

- *Develop rules for wholesale markets that require explicit consideration of the environmental characteristics of all competing generators.*

- *Create incentives for retail electricity suppliers to promote end use efficiency improvements.*

- *Ensure that renewable generation has equivalent access to transmission services when such services become unbundled.*

- *Create incentives for the distribution and retail components of unbundled power sectors to fully consider distributed resource options for providing electricity services.*

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- *Adopt electricity tariff structures that provide appropriate price signals for energy efficiency.*

Initiatives outside the power sector can also improve its environmental performance. These include the following:

- *Allow environmental stakeholders to participate in the reform process.*
- *Strengthen environmental policies and institutions prior to major reforms, especially privatization.*
- *Evaluate the environmental implications of reforms being contemplated (including greenhouse gas emissions) through a programmatic environmental assessment.*
- *Complement power sector reforms by implementing reforms in other sectors that eliminate barriers to using clean fuels and technologies.*

To support the design and implementation of such measures by country policy makers, multilateral and bilateral development organizations (such as USAID and the World Bank) can provide technical and financial assistance. These organizations have a variety of tools at their disposal that can be used to:

- *Make environmental performance improvement an explicit component of technical and financial assistance to the power sector.*
- *Help developing country governments design indigenous solutions to power sector problems that promote environmental sustainability.*
- *Help in-country environmental stakeholders become more involved in power sector reform processes.*
- *Provide leadership to the independent power industry to adopt high international standards of environmental performance.*
- *Improve policy makers' understanding of how power sector reforms affect environmental performance, including greenhouse gas emissions.*

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CHAPTER 1
INTRODUCTION

1.1 THE GLOBAL REFORM ENVIRONMENT

In the past decade, two important themes have emerged in government policies for economic development. The first is sustainable development: meeting the needs of the present without jeopardizing the economic opportunities of future generations. This concept has been gaining broad acceptance since the 1992 Rio Earth Summit.

The second is a trend in which governments are liberalizing their economies and privatizing services and infrastructure. As part of this movement, Organization for Economic Cooperation and Development (OECD) and non-OECD countries are reforming the way that electricity services are provided (Exhibit 1-1). They are opening electric power generation to private investment or further privatizing transmission and distribution, and even restructuring the sector to introduce competition and independent regulation. Such reforms have been undertaken to stimulate private investment and thus free up large amounts of public capital for other uses, promote managerial accountability, improve customer service, and reduce government deficits and international debt.

Exhibit 1-1
Common Power Sector Reforms

The term "reform" is used in this report to denote a broad range of changes in the power sector that could include one or more of the following:

- making statutory changes that enable subsequent reforms and creating necessary regulatory authority
- corporatizing and commercializing the management of public utilities, which might include full cost recovery through subsidy removal
- introducing private sector management or ownership of generation, transmission, and distribution assets and operation
- creating wholesale power markets in which independent power producers compete to sell to the grid
- functional unbundling of generation, transmission, distribution, and retail services
- creating retail markets in which private entities compete to supply electricity services to customers.

Power sector reforms have profound implications for environmental sustainability.[1] Such reforms potentially affect which power generation technologies are selected to meet growing demand, the extent to which demand is mitigated by end-use efficiency improvements,

[1] Power sector reforms also have strong implications for other social issues such as equity in the provision of electricity services and sectoral employment. While these issues may be important considerations in many countries, they are beyond the scope of this report.

and the level at which air emissions from new generation are controlled. Yet, the net effect of these and other changes on environmental performance is not always clear.

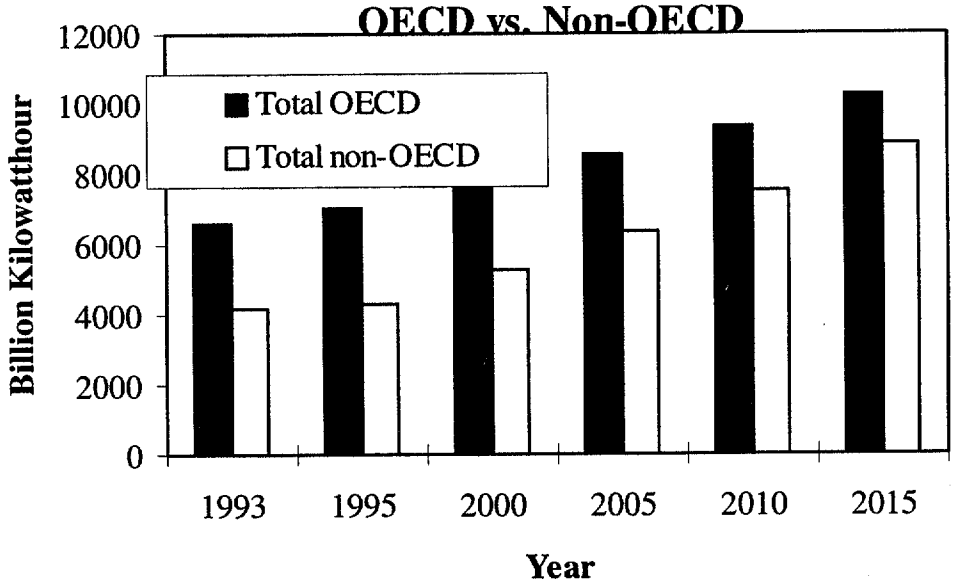
The reform process is moving ahead quickly in many countries and gathering strength in others, regardless of its environmental implications. Consequently, it is important to understand the ways in which this process can serve and influence both economic and environmental objectives. Given the momentum already present, decision makers have an opportunity to guide the reform process in directions that have favorable environmental outcomes at less cost than taking remedial actions at a later date.

1.2 OPPORTUNITIES FOR IMPROVED ENVIRONMENTAL PERFORMANCE

There has been little comprehensive analysis of the environmental implications of power sector reforms in industrialized countries or in developing and emerging economies. This is partly a function of the short history of such reforms. However, the lack of analysis has not hampered debate. Some observers argue that improved environmental performance will be a side effect when certain reforms improve the power sector's economic and managerial performance. Others posit that privatization and competition will reduce concerns over anything except the "bottom line." Speculation has been particularly intense in the United States, where reform proposals have been introduced at both the federal and state government levels.

Despite the current debate surrounding the environmental effects of power sector reforms in the United States, the opportunities and risks are greater among developing and emerging economies. Their total growth in generation between 1993 and 2015 is projected to exceed that of industrialized countries (Exhibit 1-2). Among the major regions, non-OECD Asia (Asia without Japan) is projected to have the largest growth in both electricity consumption and carbon emissions (Exhibits 1-3 and 1-4).

Exhibit 1-2
Projected Total Net Electricity Consumption, 1993-2015
OECD vs. Non-OECD



Source: Energy Information Administration, International Energy Outlook 1997, U.S. Department of Energy, Washington, D.C., April 1997.

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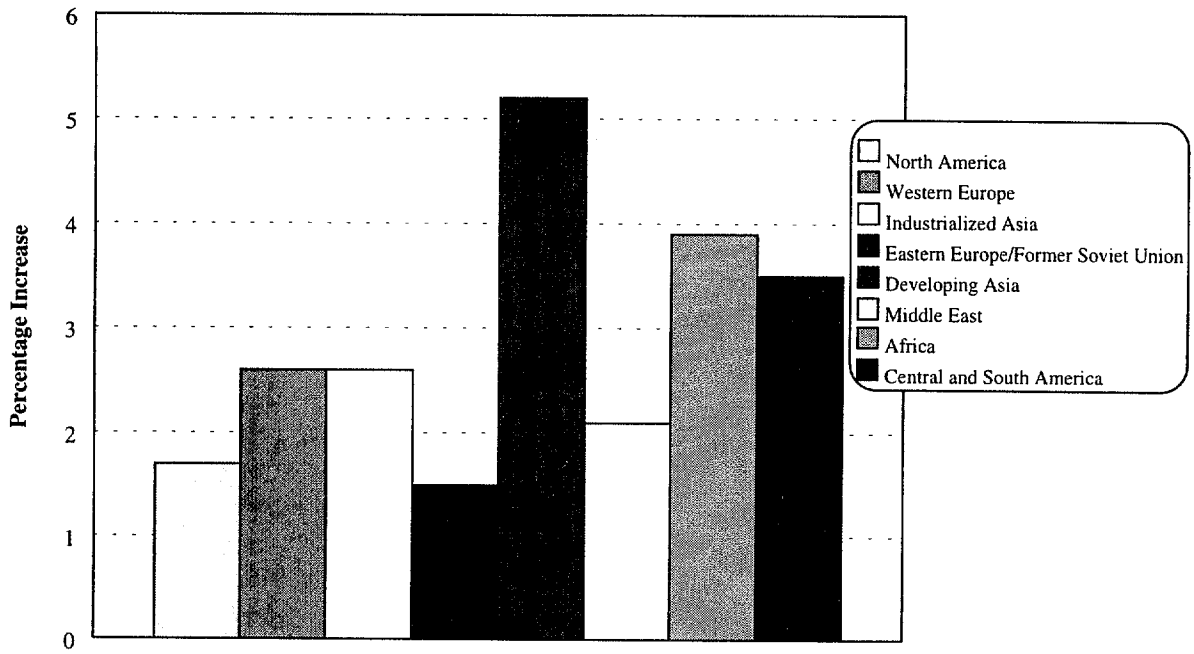
Exhibit 1-3
Projected Annual Increase in Electricity Consumption by Region from 1995 to 2015



Source: Energy Information Administration, International Energy Outlook 1997, U.S. Department of Energy, Washington, D.C., April 1997

There are several reasons for giving attention to the environmental implications of reforms at this time. First, by creating momentum for institutional change, the reform process offers a window of opportunity that can be used to improve the environmental performance of developing countries' power sectors (e.g., new incentives affecting the choice of technologies used for energy services). Countries that have initiated or completed reforms represent about 756,153 MW, equivalent to 78% of the total non-OECD (plus Mexico) generating capacity.[2] Because of rapid economic growth rates (sometimes in the double digits), capital investments made in these countries over the next 20 years will be larger than their investments made under pre-reform regimes.

Second, power sector decisions have long lasting implications. Capital investments in supplying or using electricity last a long time (up to 30-40 years for power plants); in addition, investments made in one part of the sector affect investments in the others. For example, the size and location of a new power plant have direct implications for transmission system investments. Even factors outside the power sector such as the efficiency of industrial processes affect distribution,

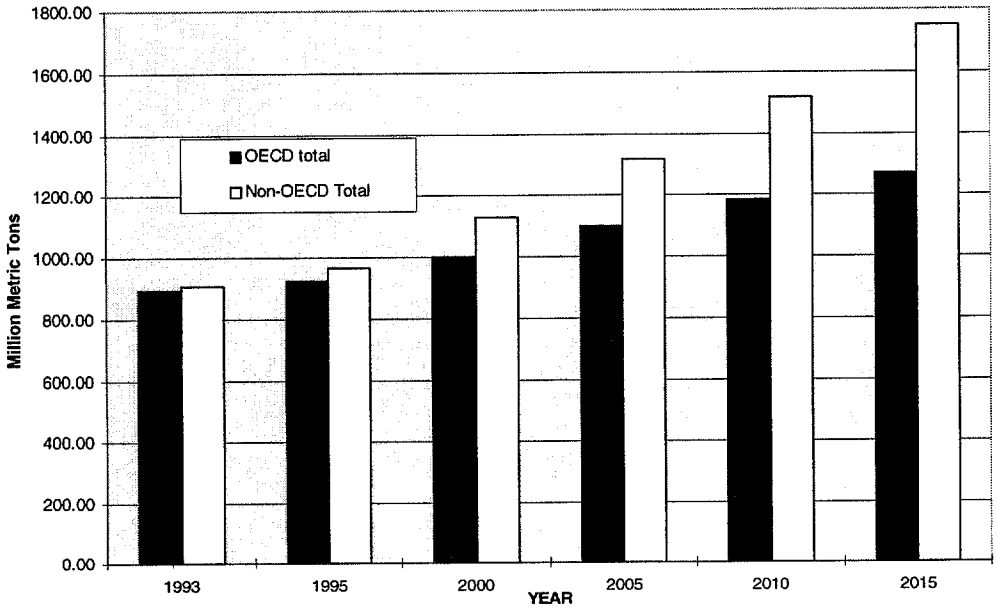
[2] Jamshed Heidarian and Gary Wu, *Power Sector Statistics for Developing Countries, 1987-1991*, December 1994; and Energy Information Administration, *International Energy Annual, 1995*, December 1996.

transmission, and generation requirements. The fact that major infrastructure investments and institutional reforms are expected to occur over the next decade in countries representing a majority of non-OECD generation capacity means that the reforms will influence electricity supply and end-use investments for decades to come.

Third, as reforms move forward, policy makers are still paying insufficient attention to their implications for energy supply and demand choices. In addition, such key environmental stakeholders as environmental agencies, non-governmental organizations, urban and rural consumers, and communities adjacent to power plants have had little involvement in power sector reforms.

Fourth, examining this issue now would help ensure that power sector models that are being replicated are environmentally as well as economically sustainable. Historically, models pioneered in one country have been widely observed and emulated elsewhere. In the 1940s and

Exhibit 1-4
Electricity Related Carbon Emissions 1993-2015
OECD vs. Non-OECD



Source: *International Energy Outlook, 1996* ; Energy Information Administration, DOE; Washington, DC.

1950s, developing countries generally modeled their power sectors on that of their main economic partner among industrialized countries (usually Britain, France, or the United States).

In the 1980s and 1990s, the Chilean and Argentinean reform models have been sweeping Latin America (Guatemala, Bolivia, Colombia, Peru). Also in the 1990s, independent power development has been spreading across Asia, Central America and the Caribbean, although with

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less competition than in the United States. In addition, Francophone Africa has been experimenting with privatizing utility management using models adopted by France, its main economic partner.[3]

All of these reform models have implications for the environment that will be discussed in the following chapters of this report:

- Chapter 2 outlines how various decisions made within the power sector can influence the environment. Though power sector actions affect the environment in numerous ways, this investigation has focused on the implications for air emissions.

- Chapters 3 and 4 discuss four main types of power sector reforms (commercialization, privatization, unbundling and competition) and describe how those reforms affect air emissions.

- Chapters 5-7 are case studies of power sector reform experience in the United Kingdom, Argentina, and India that illuminate how individual country circumstances can affect the design and implementation of the power sector reform models discussed in Chapters 3 and 4.

- Chapter 8 presents results of a modeling exercise to further evaluate the effects of various reforms on air emissions, focusing on a hypothetical developing country as well as a state in India.

- Finally, Chapters 9 and 10 present conclusions from this study and recommendations for ways in which developing country policy makers and multilateral development banks can structure reforms or provide technical assistance to promote improved environmental performance in power sector reform decision-making.

[3] Besant-Jones, John, "The England and Wales Electricity Model — Option or Warning for Developing Countries?" *Viewpoint*, The World Bank Industry and Energy Department, Washington, DC, June 1996.

CHAPTER 2
HOW POWER SECTOR DECISIONS AFFECT THE ENVIRONMENT

Several types of power sector decisions made by utilities, government agencies, and electricity consumers directly or indirectly affect environmental quality (see Exhibit 2-1). Although all of these environmental indicators are important, the influence of power sector reform activities on air emissions is the primary focus of this study. Relevant decisions include the following:

- siting, type, and operation of generating capacity
- transmission and distribution investment
- demand-side management (DSM) efforts
- electricity price signals
- technology commercialization investments , and
- environmental mitigation measures.

The purpose of this chapter is to summarize the various points at which power sector decisions affect environmental performance. It focuses on air emissions to compare the effects of different decisions; however, other environmental effects can be as or more important than air emissions for some systems , depending on their particular characteristics.

Power sector decisions affect the environment through multiple and interacting pathways. For example, Exhibit 2-2 shows that air emissions are affected by how much energy is wasted at various points in typical power systems. In this example, the environmental effects of energy wasted at the point of end use are magnified by upstream energy losses.

Exhibit 2-1
Examples of Environmental Effects of Electric Power Systems

Each type of power generation has a particular set of environmental impacts, which makes the total environmental impact difficult to compare. *Thermal* generation has the following environmental impacts:

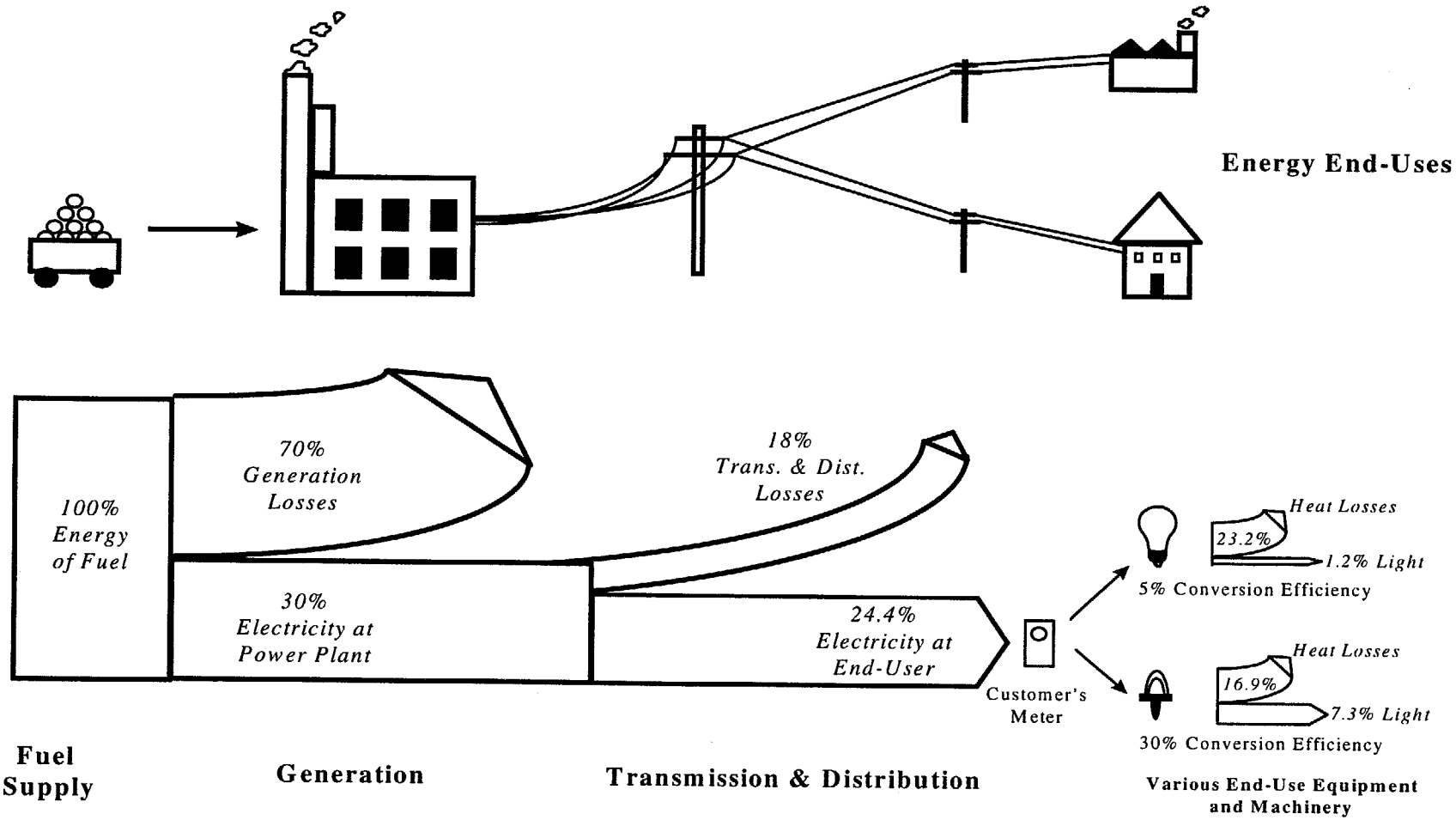
- Air emissions (conventional pollutants, greenhouse gases, air toxics)
- Thermal discharges from cooling water
- Land consumption and terrestrial impacts from siting generation, transmission, and distribution infrastructure
- Fuel extraction (e.g., open-pit versus underground mining)
- Fuel transport and storage (e.g., pipelines, ports, rail)
- Fuel processing (e.g., coal washing)
- Ash disposal.

In contrast, the environmental impacts of *hydropower* are related more to land use:

- Loss of riverine and terrestrial ecosystems
- Relocation of human settlements
- Disruption of regional hydrologic cycles
- Greenhouse gas emissions from vegetative decay
- Water quality problems
- Fisher y disturbances.

Environmental impacts from *nuclear* power plants differ from those of fossil and hydro generation, and tend to center around the disposal of radioactive waste and safety problems associated with radioactive leaks. Nuclear fuel cycles also have land use and fuel extraction impacts.

Exhibit 2-2
Environmental Implications of Energy Losses



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Changes in air emissions over time reflect the rate of change in and strength of several relationships inherent in power sector decision-making. While, for example, replacing old, outmoded, or inefficient capital stock will reduce the average emissions generated per unit of end-use service provided, such environmental gains may be offset by growth in consumer electricity demand. According to a World Bank modeling exercise, taking cost effective actions to slow the growth in kWh demand per unit of GNP and reduce the primary fuel input required per unit of electricity demand would reduce projected levels of emissions growth in the developing world by about 28% in the year 2030. However, even with these improvements, developing country emissions would still increase eightfold between 1990 and 2030 due to growth in total electricity demand. In order to hold developing country emissions roughly constant between 1990 and 2030, the study concluded that markedly improved generation technologies must be used to meet the growth in electricity demand.[1]

Conceptually, the environmental effects of growth in electricity use also include indirect positive and negative environmental effects from the growth of other sectors served by electricity. Increased electrification, for example, might generate environmental benefits from improved water supply, while at the same time increasing negative environmental impacts from electricity-intensive industries.

2.1 GENERATING TECHNOLOGY

The choice of generating technology is fundamental with respect to air emissions. Non-thermal generation technologies do not emit air pollutants (with the exception of minor emissions from geothermal generation). Among the thermal generation technologies, the level of air emissions per kWh is determined by design, fuel type, heat rate, and emission controls. As Exhibit 2-3 shows, for example, particulate and sulfur dioxide (SO_2) emissions can be essentially eliminated by avoiding coal and oil generation. All fossil generation emits some nitrogen oxides (NO_x) and the greenhouse gas carbon dioxide (CO_2), but natural gas generation emits less of these per kWh than conventional coal generation.

Once the overall type of generation is chosen, plant design characteristics also affect emissions. While fossil fuel generators have some fuel flexibility, they are designed to operate optimally using fuel with specific characteristics. For example, a coal plant is designed to efficiently burn fuel whose sulfur, heat, moisture, and ash contents are within a specific range. In addition, the thermal efficiency of the combustion process, burner design, and choice of stack controls affect emissions per kWh. Finally, the location of the plant determines how its emissions affect ambient air quality, which is of ultimate concern for human health and ecosystem functioning.

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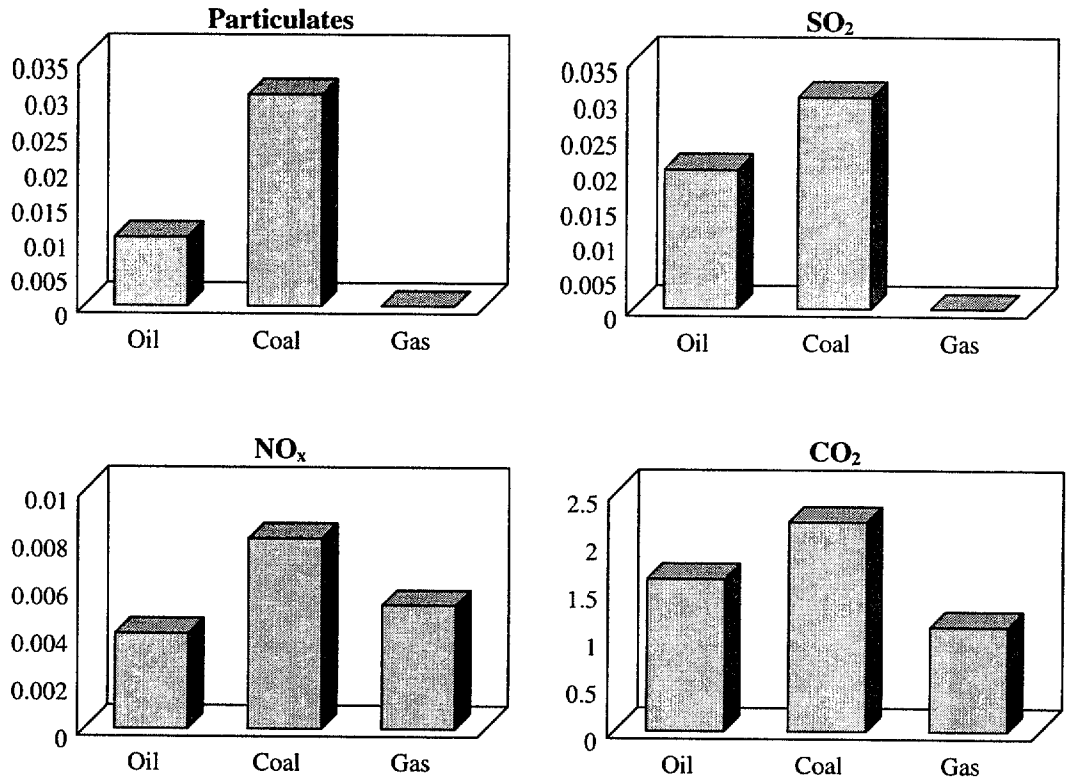
[1] Anderson, Dennis and William Cavendish, "Efficiency and Substitution in Pollution Abatement: Three Case Studies." *World Bank Discussion Paper 186.* Washington, DC: The World Bank, 1992.

Exhibit 2-3
Typical Air Emission Factors for Thermal Generation
(pounds/kWh)



2.2 POWER PLANT OPERATION

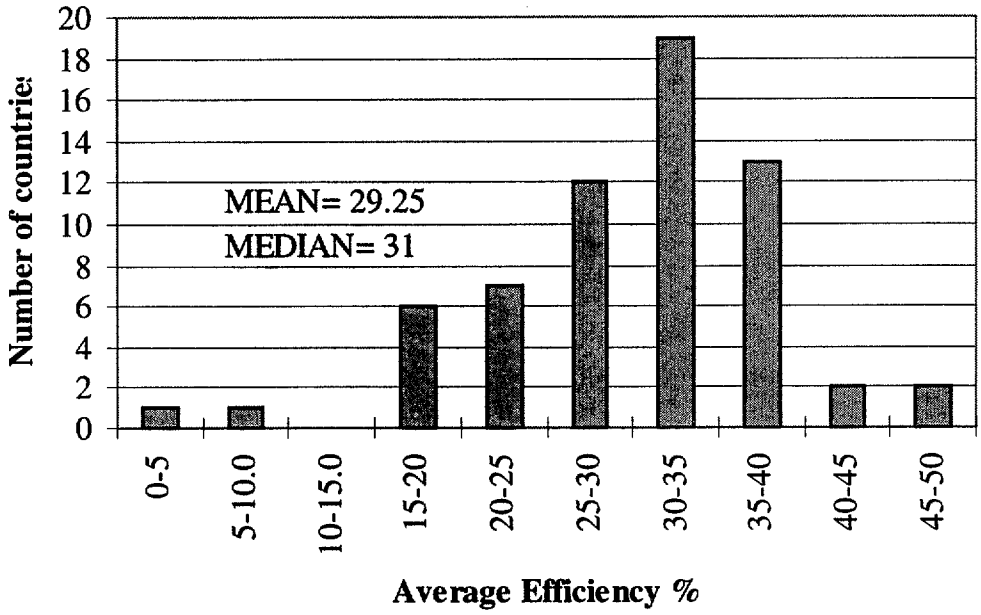
Once a generation project using fuel of a given quality is built, its annual emissions are determined by how much electricity is produced, which in turn is influenced by the unit's duty cycle (base, intermediate, or peaking). For a given fuel source, base load units generate the highest absolute annual emissions, although they may have low per kWh emissions. A unit's duty cycle is in turn determined by the power system's load shape and the incremental cost of running the unit relative to other units.

The operation and maintenance procedures followed at a plant, along with the type of fuel burned, determine whether it achieves its design standards for operating efficiency and environmental performance. Inadequate attention to maintenance can lead to equipment malfunction. For example, two of the five electrostatic precipitators at a 324 MW coal-fired plant in New Delhi (which normally remove 97% of fly ash emissions) were out of service for several

weeks in 1996, resulting in fly ash emissions of 1,500 tons per day in the densely populated plant area during the malfunction.[2]

Emissions are also affected by the design efficiency of thermal generation and how close to its design efficiency the plant operates. The mean design efficiency of thermal plants in 63 developing countries in 1990 was 29.25% (see Exhibit 2-4).[3] This is at least 5% below the average efficiency of thermal generation among OECD countries resulting in greater fuel combustion for the same amount of power.

Exhibit 2-4
Average Thermal Plant Efficiency
Among 63 Developing Countries



Source: Heidarian and Wu, op. cit.

[2] Patel, Tara, "Power Station Failure Adds to Delhi's Woes." *New Scientist,* Oct. 12, 1996, p. 8.

[3] Heidarian, J. and G. Wu, *Power Sector Statistics for Developing Countries, 1987-1991.* The World Bank, Industry and Energy Department, December 1994.

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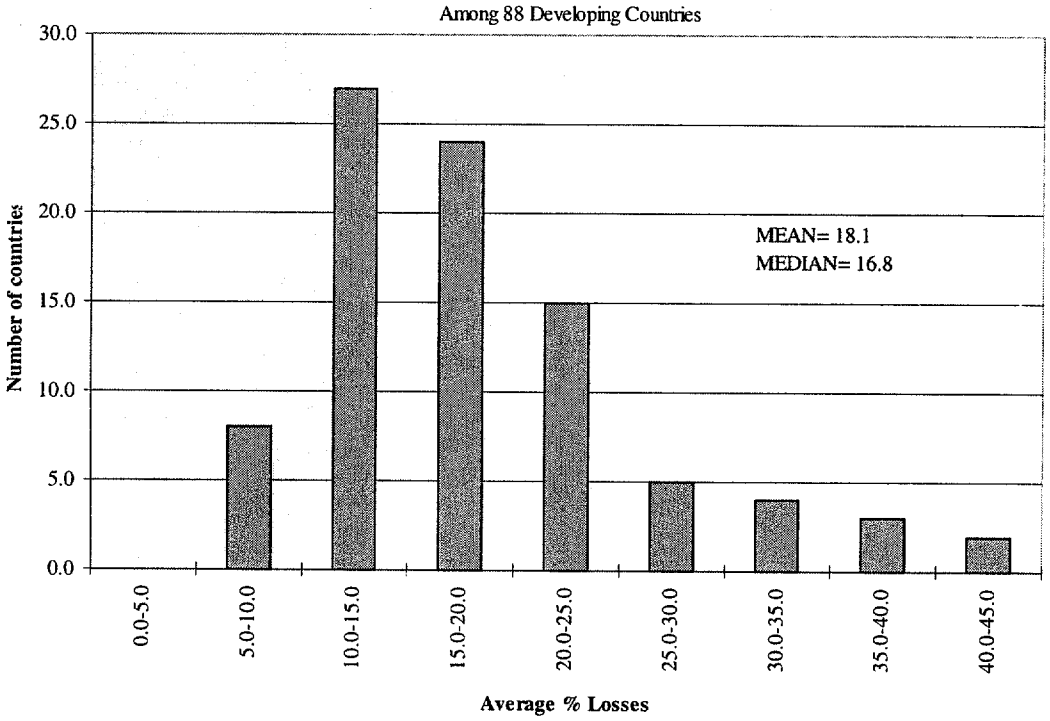
2.3 TRANSMISSION AND DISTRIBUTION SYSTEM

Transmission and distribution (T&D) energy losses increase the air emissions per delivered kWh. Decisions about investing in and operating T&D systems affect how much of the power generated is actually delivered to customers. Energy losses occur due to under-investment in T&D infrastructure, inefficient operation, and theft. While energy losses range widely among 88 developing countries, as shown in Exhibit 2-5, the mean of 18.1% is well above the losses of 5%-10% typically found among OECD countries.[4]

Exhibit 2-5
Average Transmission and Distribution System Energy Losses
Among 88 Developing Countries



Source: Heidarian and Wu, op. cit.

Transmission infrastructure investments have other potential effects on emissions. First, interconnections determine the extent of power trading among utility systems outside a region or a country. Some countries experience transmission bottlenecks that prevent power exchanges among regions (or across national borders), which inhibits the use of existing generating capacity in the system. As a result of such system imbalances, electricity shortages may occur in some

[4] Ibid.

areas of a country even while surplus capacity exists in others. The environmental implications depend on the type of capacity whose use is inhibited. In India, for example, transmission bottlenecks reduce generation from mine mouth coal plants in one state, and generation from wind power plants in another. Local capacity shortfalls can lead to customer investment in high-cost and often more polluting self-generation. Capital investments in transmission infrastructure could overcome bottlenecks, lower the incentive for customers to generate their own electricity, and reduce the need for the power sector to add new generation.

The environmental effects of inter-utility or cross-border trading in power depend on how the capacity factors of different power plants change.[5] Since new units are often less polluting than old units, greater use of the existing fleet could increase overall emissions. In India, better transmission interconnections are modeled to increase the capacity factor of coal-fired generation, which has lower marginal costs but higher emissions than other generators.[6] A similar analysis of better interconnection conducted in Africa, however, projected a net increase in hydro generation.

2.4 EXPANDING ELECTRICITY SERVICES

Emissions are also affected by decisions on how the energy needs of unconnected customers are to be met. Off-grid households might be served by conventional grid extension, village mini-grids powered by renewable or diesel generation, or household-level generation. Some developing countries have large rural populations that are not served by the electrical grid and are unlikely to be served in the near future. Other rural and urban customers are nominally served, but service is so unreliable that they choose to invest in their own sources of generation. Self-generation, in fact, constitutes an average of 13% of total (public utility plus self-produced) generation in the 75 developing countries for which such data are available, and its proportion is over 25% of total generation in 12 (mostly African) countries.[7]

In countries with unmet demand for grid power, the ways in which unserved customers meet their electricity needs also has environmental implications. Self-generators use a higher proportion of diesel capacity than utilities do, and emission factors are apt to be higher due to their small size and operating conditions. In many countries, environmental laws or their enforcement apply to generating units in the power grid, but not to self-generation because of

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[5] Plant capacity factor = actual annual MWh generation / capacity (MW) * 8760 hours.

[6] Parikh, Jyoti, D. Chattopadhyay, and U. Nandapurkar, "Simulation of National Grid Operation in India." *Utilities Policy.* Vol. 5, No.1, pp. 65-74, January 1995.

[7] Heidarian and Wu, op. cit.

capacity size, ownership, or other factors. Further, captive generation is more likely to be located in urban areas where emissions have greater health impacts.

In many developing countries, universal electrification is a national goal. Public utilities, which are responsible for achieving this goal, have often been required to extend the grid to rural areas without having the tariff structure or collection ability to recover the costs of service. Rural electrification has thus often been implicitly or explicitly subsidized by urban electricity customers or by transfers from the national treasury. (This situation has also been true historically for OECD countries.) Because the ability to subsidize rural electrification is limited, grid extension has proceeded slowly.

In expanding the power sector's infrastructure, a fundamental choice — with weighty environmental implications — exists between conventional grid extension and the use of so-called "distributed generation resources." The latter refers to small-scale resources located close to where power is actually needed, in contrast to the central station generation approach (Exhibit 2-6). Environmental implications are positive because renewable energy technologies, fuel cells, and other low-polluting forms of generation are well suited to the distributed approach and because energy losses are reduced. While the distributed resource concept has been pioneered in Europe and the United States, it has wider application in developing countries, which have larger rural and currently unserved populations.

Exhibit 2-6
Distributed Utilities: A New Paradigm for Power Sector Infrastructure?

The distributed utility paradigm has characteristics that appear well suited to the conditions prevailing in many developing countries, including:

- Uncertainty in the demand for power in currently unserved areas, suggesting an incremental approach to investment
- High marginal transmission and distribution costs
- Relatively dispersed loads with many unconnected areas
- High transmission and distribution energy losses
- Unreliable interconnections and poor local power quality.

Because embedded power sector infrastructure investments in developing countries are still too small to meet projected demand, these countries could potentially leapfrog to a distributed utility model. Successful examples of this can be seen in countries where telecommunications systems have bypassed wires and leaped to cellular phones, and where information processing has skipped the mainframe stage and gone directly to desktop computers.

The distributed utility approach to serving electricity needs offers several other advantages. T&D energy losses from extending the grid into remote rural areas can be reduced, and environmental impacts to meet a given load can be lessened, all else being equal. Local demand peaks, which are often costly to serve, are reduced. Excess power can be wheeled to customers outside the immediate grid. Power quality can be improved. Finally, capital-strapped utilities can phase in investments. That is, local grids can be developed first and, when demand rises sufficiently, can be connected to the transmission system.

2.5 DEMAND-SIDE MANAGEMENT

Air emissions from a utility are significantly affected by the electricity system's load curve, whose shape influences how different generating units are dispatched (their deployment and duration of use). Each unit has different emissions characteristics. The

system load shape is determined by the demand patterns of various customer classes, which in turn are determined by the rhythm and pattern of customer lifestyles and economic activity, electricity tariff structures, the efficiency and size of end-use equipment, and substitution between electricity and other energy forms.

The environmental effects of changes in load shape and end-use efficiency depend on when and where these changes occur. In general, the environmental effects of energy efficiency measures depend on total energy savings,[8] resulting changes in the dispatch of different units at the margin, and generation emission factors. For example, improving the efficiency of an end use such as refrigerators, which is used throughout the year, would have relatively large energy savings compared to a measure that primarily affects peak demand, such as air conditioning. However, the impact of reducing refrigerators' energy use would partly depend on what types of plants supply baseload and peak power. Thus, if the baseload generation is hydro and peak load generation is oil-fired, then improving air conditioning efficiency has a greater emission reduction per kWh saved. The interplay of all of these factors makes it difficult to generalize and predict the outcome of a given measure without knowing specific power sector characteristics.

In most developing countries, there is a large potential for reducing the electricity required to serve a given level of end-use need. Potential environmental benefits from energy conservation measures are typically not realized, however, due to a combination of market failures (e.g., uninternalized environmental costs), government policy distortions (e.g., energy subsidies and regulatory distortions), and other barriers (e.g., inadequate information, high discount rates, unobserved costs, principal-agent slippage, heterogeneity among potential adopters). Estimates vary widely (0%-20%) as to the size of the energy conservation gap (defined as the gap between potential and actual energy savings), partly because of differing definitions of conservation potential.[9]

Power sector decisions can affect electricity-using equipment and usage patterns by setting electricity prices and tariff structure, and by promoting changes in through demand-side management (DSM) programs. The roles played by the government and/or the power sector in overcoming barriers to achieving the conservation potential vary from country to country. Some programs simply provide information about energy saving opportunities to customers; others share the actual investment in an energy saving measure with the customer or help to finance it. In addition to such customer-focused programs, market transformation programs work with trade allies such as equipment manufacturers to upgrade the overall efficiency of the equipment stock entering the market. Developing countries with ministries or power sectors that have begun

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[8] Fenichel, Anita. *Impacts of Demand Side Management Programs on the Environment.* Alliance to Save Energy, Washington, DC, 1993.

[9] Energy Modeling Forum, *Markets for Energy Efficiency.* EMF Report 13, Volume 1, Stanford University, September 1996.

significant energy efficiency programs include Brazil, Pakistan, Thailand, Mexico, Jamaica, and the Philippines.

In a few countries, vertically-integrated utilities have begun to conduct integrated resource planning (IRP) in which the utility identifies a portfolio of generation (supply side) and DSM resources that meet the future need for power on the basis of least cost. When a utility practices IRP, different tests may be applied to determine the cost-effective level of investment in end-use efficiency measures. Each test has implications for which energy efficiency measures are deemed cost-effective (see Exhibit 2-7). While these tests were developed in the United States, they are beginning to be applied in developing countries, such as India.[10] (These tests were designed for use with vertically-integrated utilities; new tests may need to be applied to various reform scenarios.)

Exhibit 2-7
Accounting Perspectives for Energy Efficiency Measures

Perspective	Benefits	Costs
Utility	Avoided supply costs[11]	Utility cost of DSM measures and marketing
Ratepayer (rate impact measure)	Avoided supply costs	Utility cost of DSM measures and marketing plus lost revenues
Society (total resource cost)	Avoided supply costs	Utility cost of DSM measures and marketing plus net customer costs
Society (total social cost)	Avoided supply costs plus external costs	Utility cost of DSM measures and marketing plus net customer costs
Participant	Bill savings	Net customer costs

2.6 ELECTRICITY PRICE SIGNALS

The price signals received by retail customers are determined by electricity tariff structures, which include the price of inputs to electricity production , such as fuel, equipment, labor, etc. In addition, customers will respond to tariff structures based on their expectations about the effectiveness of revenue collection. If customers have a reasonable expectation that their bills will never be collected (which is the case in a number of developing countries), then tariff

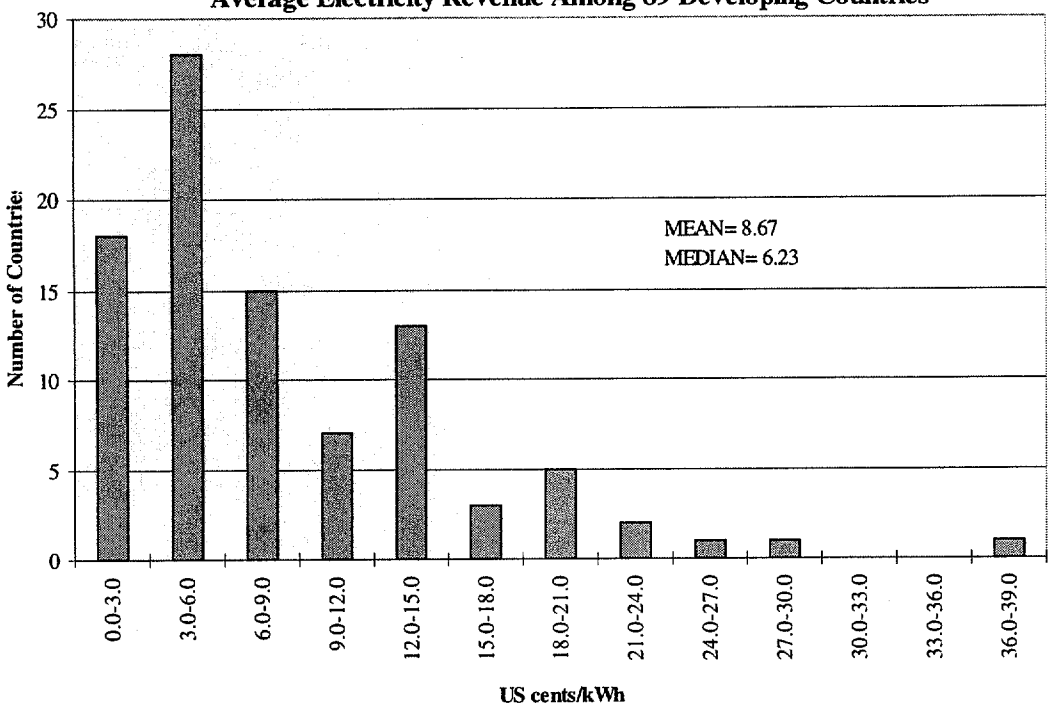
[10] See, for example, Parikh, Jyoti, Sudhakara Reddy, and Rangan Banerjee, *Planning for Demand Side Management in the Electricity Sector*. New Delhi: Tata McGraw-Hill Publishing Company Limited, 1994.

[11] For vertically-integrated utilities, these include generation, transmission and distribution costs.

structures will have little to no effect on end-use consumption behavior. However, if bills are regularly collected with sanctions for nonpayment, the price signals received by end-use customers can strongly affect the pattern and growth of electricity demand, which in turn, affect generation emissions.

Electricity tariff structures do not provide appropriate price signals for efficient electricity use when they do not reflect the marginal costs of new supply. According to World Bank data, the mean 1992 electricity revenue in 89 countries was US $0.087/kWh and the median was only US $0.0623/kWh,[12] about 60% of the average revenues collected by utilities in OECD countries which more closely approach true costs (see Exhibit 2-8). Moreover, real tariffs declined in many countries during the 1980s when costs were actually rising.

Exhibit 2-8
Average Electricity Revenue Among 89 Developing Countries



Source: Heidarian and Wu, op. cit.

In many developing countries, tariff subsidies and customer cross-class subsidies have often been determined on the basis of political sensitivities and social programs imposed on the power sector. In India and Pakistan, for example, rates have often been highly subsidized for

[12] Heidarian and Wu, op. cit.

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agricultural water pumping. In Indonesia, customers in Java subsidize customers on other islands. In Brazil, large electricity-intensive industries are given subsidized rates.[13] In Ukraine, the majority of residential customers have received some form of electricity price subsidization. The environmental implications of tariff subsidies depend on the load profile and price elasticity of those customer classes that use more electricity than if they paid the true costs of service. (Although tariff reform remains a difficult political issue, several countries have made substantial progress in this regard.)

Consumption patterns are also influenced by the extent to which tariff structures reflect the time- and location-specific costs of service. Few utilities, even in the United States, use tariff structures that accurately reflect such locational costs.

As a significant component of electricity costs, fuel costs also affect power consumption. In many developing countries, fuel extraction and transport are the province of a public enterprise or a quasi-public corporation that is protected from international competition. Total fossil fuel subsidies among developing countries are estimated to be about $210 billion as of 1991, equivalent to 20%-25% of the value of world fossil fuel consumption at world prices. The removal of such subsidies would increase electricity prices, inducing a reduction in demand as well as an estimated 7% reduction in global carbon emissions.

Of the fossil fuel subsidies, those to natural gas and coal consumption for power generation in nine countries totaled an estimated US $21.65 billion and US $16.25 billion, respectively, representing roughly 18% of the total potential carbon emission savings from subsidy removal.[14] Of course, even if purchased fuel prices were to reflect world prices, a public utility buying fuel from a public coal enterprise may not actually repay the full costs. Similarly, fuel transport, off-loading, and storage costs may be subsidized, especially where such facilities are public enterprises. (As with tariff structures, several countries have reduced these subsidies under broad economic reforms.)

Price signals also have indirect environmental effects through their impact on economic consumption and production activities that require electricity as an input. For example, the availability of virtually free but unreliable electricity to pump water in rural India has led to an alarming drawdown of groundwater resources. Because farmers typically pay for power based on the size of their pump, not the amount of electricity they use, and are unsure of when power is actually available, they simply leave their pumps running during critical growing periods.

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[13] Geller, Howard, *Efficient Electricity Use: A Development Strategy for Brazil.* Washington, DC: American Council for an Energy Efficient Economy, 1991.

[14] Larsen, Bjorn, "World Fossil Fuel Subsidies and Global Carbon Emissions in a Model with Interfuel Substitution." *Policy Research Working Paper, 1256.* Washington, DC: World Bank, February 1994.

Government policy can also affect electricity demand by subsidizing indigenous industries. The Brazilian Government has had a policy of encouraging and subsidizing domestic metals production and export. Metals production is electricity-intensive and polluting in its own right. Government policy to protect polluting industries thus affects the environment directly (the pollution from the industries) and indirectly (by driving up power demand).[15]

Price signals by themselves are effective in causing efficient electricity use patterns only if the power sector has effective metering and revenue collection practices that are not subject to corruption. Otherwise, it may be less expensive for a customer to bribe the meter reader than to invest in energy saving measures. Revenue collection problems are endemic in many developing countries.

2.7 COMMERCIALIZATION OF ENVIRONMENTALLY- SUPERIOR TECHNOLOGIES

The technological choices available around the world for generating, transmitting, distributing, and consuming electricity have changed in response to evolving conditions in electricity markets. Innovations in information processing have enhanced the potential for direct load control by allowing the power supplier to, for example, turn off a customer's air conditioner during peak periods. Bringing an environmentally-superior technology to commercial maturity may require research and development (R&D), demonstration projects and pilot programs prior to full implementation. Such initiatives require a stream of investments either by the power sector itself or by other stakeholders.

While several (especially larger) developing countries, such as Brazil, conduct large R&D programs, OECD countries have historically been the source for technologies adopted by developing country power sectors. This dependence on external investment for commercialization has two implications. First, it means that the portfolio of technologies available for transfer to developing countries reflects the priorities and conditions among OECD country power sectors. Second, it means that shifts in levels of overall R&D investment in OECD power sectors will have downstream effects on continued performance improvements in developing country power sectors.

Dependence on technologies developed and commercialized in OECD countries means that developing countries tend to follow the central station paradigm for structuring their power systems, even though innovations in distributed resource technologies offer an alternative. OECD power sectors generally place a low priority on commercializing technologies for off-grid rural areas because their potential application is small, whereas in developing countries such

[15] Geller, Howard, op. cit.

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technologies could constitute major markets. Some emerging environmentally-superior technologies (for example, photovoltaics), are characterized by declining costs as a function of total production. That is, as the cumulative number of installations of these technologies grows in high-value markets, their unit costs are expected to decline, opening up new markets for them. For such technologies, diffusion in rural markets is a critical step to their becoming cost-competitive in grid-connected markets (Exhibit 2-9).

Photovoltaic, wind, and small-scale biomass generation tend to be most cost-effective in serving off-grid rural areas because they are competing with high cost grid extension and because locally-available renewable resources can serve the relatively modest rural levels of demand.

2.8 ENVIRONMENTAL CONTROLS

A review of relevant environmental laws and the capacity of environmental policy-setting institutions in several countries undergoing power sector reforms (Argentina, Chile, India, Malaysia, Pakistan, the Philippines, Poland, Ukraine, and the United Kingdom) was conducted for this study. These countries vary widely in a number of ways, including: their overall institutional capability for establishing and enforcing environmental policy; the existence of air quality regulations; the provision of information about the environmental impacts of individual projects; and the ability of environmental stakeholders to participate in developing sectoral policies that affect the environment (see Appendix A).

In these countries, environmental policy governing the power sector is established and enforced by different agencies than those

Exhibit 2-9
Technology Lock-In

When the early market penetration of a technology leads to a more attractive product or to a market infrastructure geared to the successful technology, which further increases its market share, the technology can become locked in the market. Once lock-in occurs, no existing technology can effectively compete, even when it is cheaper or better than the locked-in technology.[1] Conventional power generation technologies are now firmly locked in industrialized countries, where embedded transmission and distribution infrastructures support central station generating plants, generating capacity portfolios have been optimized by developing a mix of units designed to operate at specified duty cycles, power on demand at any cost is the established performance norm, and capital markets are accustomed to the risk and return characteristics of conventional technologies.

While conventional technologies appear locked-in to the well established grids in industrialized countries, it is less clear which technologies will be the winners to serve the two billion plus people currently unserved by electricity in developing countries. Renewables are often cost-competitive in these off-grid markets, and have the potential to penetrate them at a scale that will drive down their cost sufficiently to be able to challenge the lock-in of conventional technologies in the grid-connected markets. Several renewable technologies are experiencing decreasing costs and are expected to achieve further cost decreases with scale of production and cumulative production experience. Because markets do not exist for future users to compensate early adopters, however, renewable equipment suppliers are slow to make investments in cost-reducing production capacity — the well-known chicken-egg problem.

[1] Cowan, Robin, and David Kline, "The Implications of Potential Lock-In in Markets for Renewable Energy." Presented at the International Symposium on Energy and Environmental Management and Technology, Newport Beach, CA. Published by National Renewable Energy Laboratory, 1996.

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developing power sector policy reforms. Moreover, environmental policy has not been re-evaluated in the context of power sector reform. To the extent that an environmental impact assessment process exists, it covers individual projects but not government policies.

In most countries, environmental agencies have no explicit authority to participate in policy-setting in the power sector. The fact that environmental laws and policies are still evolving exposes the country's environment to the risk of poorly-regulated power sector development, not to mention exposing power project developers to the risk that future environmental control costs may be imposed.

CHAPTER 3
COMMERCIALIZING OPERATIONS AND PRIVATIZING OWNERSHIP

Reforming the management and ownership of various economic sectors is a growing trend among developing countries. Reforms can range from introducing commercial objectives into an otherwise publicly owned and managed enterprise, to transferring the enterprise with all of its assets to private ownership. While privatization has been widespread among both OECD and non-OECD countries over the past decade, the electric power sector is typically one of the last to be privatized because politicians consider its functions to be vital to the state. This chapter discusses the typical methods by which power sectors are commercialized and privatized, as well as the impact of these decisions on environmental factors, particularly air emissions.

3.1 TYPICAL REFORMS

Commercialization

Many countries initiate the reform process by corporatizing and commercializing the national power sector while leaving it in public ownership, often under performance contracts with private managers. Corporatization involves a change in legal status — enterprises that are organized under public laws become transferred into private law companies under state ownership. In some countries, this change can be made by legislation, whereas in others, corporatization occurs enterprise-by-enterprise upon the approval of individual applications.

Commercialization involves introducing commercial objectives into the management and operation of a state-owned enterprise. Subsidies are removed, including state guarantees for borrowing, and the enterprises become subject to the same tax laws, prices and accounting rules as other private sector companies. To make a company more attractive to private investors, its past debts may be assumed, staffing reduced, and new operating capital provided. For utilities that remain in public ownership, accounting is often separated for generation, transmission and distribution costs. Decisions on investments in new assets are based on commercial principles rather than planning targets.

In Zimbabwe, for example, the financial and technical performance of the state utility is being improved by pursuing a set of monitorable performance targets (all of which are achievable within the existing legal framework), covering finance, human resources, and operations. The

second phase will seek to reform this framework to remove barriers to economic efficiency, achieve least-cost system expansion and operation, and facilitate private sector participation.[1]

An important component of broader managerial reforms is improved cost recovery, which is often required as a condition to receive concessionary loans from multilateral development banks. Cost recovery is improved by making tariff structures better reflect the true costs of providing service to various customer classes, upgrading revenue collection (more effective metering and billing practices), and reducing non-technical energy losses. In addition, lending agencies may require least-cost resource planning, acquisition, and dispatch. A few countries have begun to differentiate tariffs for some customer classes according to the time of day at which power is demanded.

Most countries view commercialization as an intermediate step toward privatization and other reforms. Others have commercialized their power sectors and introduced private management, but the government retains majority public ownership over the sector. Countries in this latter category include Côte d'Ivoire, Ghana, Senegal, Thailand, Singapore, and Malaysia.

Privatization

This set of reforms involves transferring at least some power sector assets to private ownership. The range of ownership reforms is bounded by full private responsibility for the operation of existing assets and new investment, either through long-term concession or change in ownership. Major sales of power sector assets have occurred in Latin America, with partial sales in Indonesia, the Philippines, and India.

One modest way to involve the private sector is to introduce external experience through a private management contract to run the utility. Using models pioneered by the French, Côte d'Ivoire, Guinea, and Senegal have tried privatizing their utilities' management under contract, including responsibility for operation and maintenance expenditures.

Transferring ownership from the public to the private sector is often justified on the basis of improved efficiency, given the poor operating and financial performance of many developing country public utilities. Still, the fact that efficient public and inefficient private utilities also exist (for example, in the United States) suggests that other factors than ownership may also account for economic performance differences (Exhibit 3-1).

[1] Dube, Ikhupuleng, "Institutional Reform in Zimbabwe's Power Sector." *AFREPREN Newsletter No. 20*, 1997, pp. 1-2.

Exhibit 3-1
Efficiency of Public Versus Private Ownership

Whether private ownership is necessary for improving efficiency is debatable.[1] Pollitt found that ownership per se is relatively unimportant in determining utilities' performance compared to restructuring and better management. He concluded that in the long run, privatization is likely to lead to lower generation costs through better investment planning, but not in the short run or for T&D costs.[2] The difference between the performance of OECD and non-OECD utilities may be more related to institutional capacity and implicit government regulation than ownership. Private ownership also is no guarantee of an absence of political interference.

However, privatization may be a practical necessity with respect to incentives for efficiency improvements. According to the World Bank, ""In theory, it is possible to provide the same incentive for efficient performance in the public sector as in the private sector. In practice, however, it is hard to create a clear commercial mandate and the required autonomy within the public sector."[3] Lack of autonomy also was cited as a major contributor to the poor performance of diesel generating plants in 17 developing countries.[4]

[1] Bhattacharya, Subhes, "Power Sector Privatization in Developing Countries: Will It Solve All Problems?" *Energy Sources*. Vol. 17, 1977, pp. 373-389 .
[2] Pollitt, Michael G., *Ownership and Performance in Electric Utilities: The International Evidence on Privatization and Efficiency.* United Kingdom: Oxford University Press, 1995.
[3] The World Bank, Power Development, Efficiency, and Household Fuels Division, Industry and Energy Department, *Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa.* Report # 182/96, Washington, DC, 1996.
[4] The World Bank, Central Project Team, Industry and Energy Department, *Core Report of the Electric Power Utility Efficiency Improvement Project.* Working Paper No. 46, Washington, DC, September 1991.

Full privatization typically occurs over several years and involves a sequence of steps. Statutory changes are often a necessary prerequisite. Corporatization and commercialization prepare a utility for private ownership. Liquidation allows the state to dispose of an enterprise by transferring the ownership of its assets rather than the enterprise itself. It can be used to break down an enterprise into more economically viable units for sale or to dissolve the enterprise as a public corporation before its sale or lease. (Although unbundling a vertically-integrated utility is discussed in the next chapter, this step may actually precede privatization to facilitate the sale.) Before a utility is sold to private investors, an independent regulatory authority should ideally be established although this step often occurs after the sale occurs.

Privatization options include sales to strategic investors (undertaken by Chile, Argentina, Hungary, and Australia), initial public offerings (used by the United Kingdom and Chile), vouchers to the public (used by the Czech Republic and Russia for a portion of their power systems), employee ownership, management buy-out, municipalization (not privatization per se, but a decentralization of public ownership), cooperatives (popular in the United States, Canada, and Scandinavia), debt-equity swaps, and joint ventures (formed in Argentina, Australia and

Chile, and proposed in Central and Eastern Europe). More than one of these options may be used in transferring the enterprise, and each has advantages and disadvantages.[2]

One of the most common reforms entails allowing the private development of some or all new power sector infrastructure. Countries that have at least opened generation to private investment constitute 78% of the non-OECD's (plus Mexico) currently-installed generating capacity. Developing or emerging economies that allow private power include Argentina, Bolivia, Brazil, Chile, China, Colombia, Costa Rica, Côte d'Ivoire, Dominican Republic, Guatemala, Guinea Bissau, Honduras, India, Indonesia, Jamaica, Kenya, Laos, Malaysia, Mauritius, Mexico, Morocco, Nepal, Pakistan, Panama, Peru, Philippines, Poland, Russia, South Africa, Tanzania, Thailand, Turkey, Ukraine, and Viet Nam.

The traditional method of assigning new projects for private sector development is for the utility to draw up expansion plans and assign specific projects for private financing. Another approach is to identify capacity requirements and let the private sector identify least-cost sources.[3] Several models exist for private participation in power generation, for example, Build-Own-Operate (BOO), Build-Own-Operate-Transfer, Build-Maintain-Transfer, and Build-Lease-Transfer.

Power purchase agreements (PPAs) are a key component of schemes in which private developers retain ownership of the generation facility (BOO). The PPA's most important provision is the price at which the utility agrees to buy power from the developer. In theory, this price is based on the costs that the utility avoids by not having to develop new capacity itself. However, the result of applying the avoided cost principle to specific projects depends on input assumptions, data availability and analytic tools, causing the treatment of avoided capacity costs to vary widely among utilities.

Independent Regulation

Integral to privatization is separating the regulatory/policy role of government from its commercial/operational role through the creation of an independent regulatory body. Where the private sector assumes direct tariff responsibility, transparent approaches to price regulation are required. Independent tariff regulation over those components of the power sector remaining in monopoly control is commonly associated with any package of reforms that includes privatizing monopoly services. In addition, regulators may issue licenses for new generation and other assets, and establish rules governing the operation of wholesale or retail power markets.

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[2] Hagler Bailly Consulting, Inc., *Privatization Options for the Power Industry.* Prepared for USAID, Arlington, VA, 1996.

[3] The World Bank, Power Development, Efficiency, and Household Fuels Division, Industry and Energy Department, *Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa.* Report # 182/96, Washington, DC, 1996.

The regulator's responsibilities depend on the political philosophy prevailing in a given country. At one extreme, the regulator's responsibility might be to simply get prices right, then step aside and let the market work. Here, the basic objective of regulation is to mimic the effects of competitive markets — ensure that utilities earn a return comparable to their cost of capital and have incentives to operate efficiently. Alternatively, if the view is that the power sector remains subject to market failures such as environmental externalities (which are pervasive in many developing countries), the regulator's responsibility might include correcting or offsetting such failures.

Several types of price regulation have evolved around the world, each of which creates a different set of incentives for utility behavior. In the United States, rate of return regulation has dominated historically. Under this approach, utilities are allowed to earn a specified return on their capital investments. However, over the past ten years, various state public utility commissions have been experimenting with alternatives to rate of return regulation that seek to improve utility incentives for efficiency or meet other performance objectives. For example, some states have tried to give utilities equivalent incentives (revenue neutrality) to acquire supply- and demand-side resources.

In contrast, the price cap approach fixes allowed electricity prices for longer periods of time than generally occurs with rate of return regulation. Price caps often include an upward adjustment each year to account for inflation, but also a downward adjustment to provide an incentive for the utility to improve productivity. The revenue target approach is similar, but focuses on controlling revenues rather than prices. Regulators set an allowed level of revenues based on actual costs for a test year. Over time, this level can also be adjusted for inflation and productivity. The allowed level of revenues may change to reflect increases or decreases in kWh sales levels.

3.2 ENVIRONMENTAL IMPLICATIONS

While commercializing the power sector is generally likely to produce more environmental benefits than the sector enjoyed pre-reform, the results are more mixed under various forms of privatization. Political conditions, environmental policy and regulations, financing requirements, and the availability of energy resources will affect the private sector's responsiveness to environmental concerns (Exhibit 3-2).

Commercialization

The managerial improvements associated with commercialization generally result in environmental benefits relative to pre-reform conditions. Better management is likely to mean better information on cost of service and more attention to the environmental implications of investment choices. The adoption of new accounting systems for tracking expenses and income should lead to more cost-sensitive management and reductions in operational waste, which may

otherwise be discharged as pollution. General managerial improvements will carry over to improvements in the ability to comply with environmental regulations.

Exhibit 3-2
Environmental Implications of Commercialization and Privatization

Reform	Positive Implications	Negative Implications
Commercialization	▸ reductions in operational waste ▸ increased use of least cost approaches to meeting demand ▸ greater utility and customer incentives to implement energy efficiency measures	
Privatization of Existing Assets	▸ improved operation and maintenance ▸ profit motives increase utility interest in supply side efficiency improvements ▸ price signals raise customers' incentives to use energy efficiently	▸ decreased commitment to achieving environmental and other social objectives ▸ little incentive to examine environmental factors during asset sales ▸ higher discount rates reduce utility interest in efficiency investments
Independent Regulation	▸ promotes compliance with environmental laws by issuing licenses for new capacity	
Private Investment in New Generation	▸ increased incentives to employ natural gas as the fuel source ▸ increased scrutiny of projects	▸ decreased incentives to use hydro and other renewables to supply energy, and greater incentive to use oil

By itself, commercializing public utilities has a relatively weak effect on the use of environmentally-superior technologies for bulk power generation. Still, the utility's ability to identify, evaluate and adopt new technologies may be improved. Commercialization reforms also may favor consideration of a broader range of resource options. When commercialized utilities are forced to meet cost recovery guidelines, they become more likely to meet customer demand in the least expensive manner. For example, in determining how to provide service to rural areas, the utility might compare grid extension with off-grid renewables and other distributed options.

Commercializing a public utility also improves its incentives to implement demand-side measures to the extent that it is unable to pass through the full costs of service to consumers on their bills. A commercialized utility has an incentive to reduce kWh sales in cases where the marginal costs to supply a kWh are greater than the revenues received, and should be willing to pay up to the difference (the cost subsidy) not to have to supply that kWh. Even without tariff

reform, DSM offers opportunities for improving the utility's financial balance sheet. For example, a utility could, in principle, invest in high-efficiency water pumps to reduce the electrical consumption of highly subsidized farmers and sell the saved kWh to industrial customers that pay the full cost of service. In situations where there is unmet demand for power, utility investments in demand-reducing measures do not necessarily result in "lost revenues."

Over the past few years, electricity prices have risen in real terms in most countries, partly in response to sectoral reforms. To the extent that subsidies are reduced, tariff structures adjusted to reflect marginal costs, and revenue collection is improved, customer incentives are strengthened to use electricity efficiently. If upstream sectors (fuel extraction and transport) are also commercialized, the utility's fuel costs may increase. This would increase the energy cost component of rates, further enhancing the customer incentive to adopt energy efficiency measures.

The environmental benefits of tariff reform depend on how overall demand is affected and how the load shapes of those classes previously receiving the highest subsidies are affected by their response to prices. While electricity use is generally expected to fall, net national energy consumption changes are difficult to predict because of increased production efficiency, macroeconomic effects, inter-fuel substitution, and differential price response.[4]

Privatization of Existing Assets

The political landscape and environmental policy in a country at the time assets are sold affect whether the privatized power sector will be more or less responsive to environmental concerns than it had been under public ownership. In some countries, publicly-owned power sectors that operate without any formal regulation are unaccountable to public concerns. When government utilities regulate their own environmental performance or are regulated by another government agency, enforcement is often lax. Consequently, creating independent regulation and formalizing contractual obligations may improve transparency and public participation in power sector decisions.[5] In other cases, for example municipally-owned systems in the United States, Germany, and Scandinavia, public utilities are quite accountable to their constituents. (U.S. municipal utilities have often been at the forefront of initiatives in demand-side management and renewable energy generation.)

When a public utility becomes privatized, its commitment to achieving a country's social objectives often diminishes (although government programs may fill the gap). Public systems can

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[4] The World Bank, *Expanding the Measure of Wealth: Indicators of Environmentally Sustainable Development*. Environmentally Sustainable Development Studies and Monograph Series No. 17, Washington, DC, 1997, p. 44.

[5] Pacudan, Romeo. "Power Sector and the Environment in Thailand: Will the Recent Structural Reforms Result in Better Environmental Management?" *Proceedings 20th Annual International Conference, International Association of Energy Economists*. New Delhi, 1997, pp.869-878.

more readily incorporate a range of public policy objectives, including end-use efficiency and environmental protection, than can privately-owned systems, which must be accountable to both regulators and shareholders. Moreover, private firms may have fewer obligations to share information or make known the reasons for their decisions than the public sector does.

Privatization can, however, lead to improved environmental performance by stimulating capital investment for replacing or upgrading poorly operating equipment and bringing in managerial expertise for improving operations. Some methods of transferring generation assets to private ownership (i.e., sales to strategic investors and joint ventures) are more likely than others to achieve these benefits. If the assets of a state power system are to be sold to strategic investors (either through competitive bidding or offered to a single buyer), theoretically, the environmental characteristics of generating units should affect the book value of these assets. Unacceptable levels of pollution in ongoing operations due to outdated technologies or lack of pollution controls may require significant capital investment in order for the enterprise to obtain environmental permits for future operations.

Still, neither government officials nor private investors have strong incentives to examine environmental factors. Negotiations to establish the terms of sale can be a lengthy process and the resolution of environmental questions can add months to closing a deal. Although the physical condition of the utility's assets should affect its value, the terms of sale do not generally take account of environmental factors. Government privatization officials generally want to move quickly to settle deals. While foreign investors would typically require that an environmental audit be conducted, information on an enterprise's environmental characteristics may be limited. Without national guidelines to allocate responsibility for environmental improvements, ad hoc arrangements are likely.

Other means of transferring ownership are no more likely to consider environmental attributes. When privatization occurs through the transfer of shares to private owners, environmental factors should theoretically play a role in setting a company's price. However, an examination of privatization in Central and Eastern European (CEE) utilities does not reveal evidence that share prices reflected the environmental conditions of assets. Environmental information is usually not available to those purchasing shares; investment firms being set up in several CEE countries may be in a better position than individual citizens to acquire environmental information. Similarly, environmental factors are unlikely to be considered in setting prices when ownership is transferred to workers through preferential purchases of shares.

Private Investment in New Generation

Because a primary objective of laws allowing private investment in the power sector is to stimulate an influx of capital, a successful outcome is increased generating and (where needed to overcome bottlenecks) transmission capacity. Thus, overall electricity consumption is likely to increase in countries that otherwise (in the base case of public ownership) would have continued power shortages. The net environmental implications of IPP development depend on the emissions of the new capacity and how its introduction affects the rest of the power system.

According to a review of IPPs in Asia, more stringent environmental regulations imposed on the new IPPs sometimes compel utilities to retrofit or refurbish older plants. In other countries, emission standards are kept low to reduce the cost of purchased power from the IPPs. Timing is important in that environmental standards need to be in place before new plants are designed and old plants retrofitted.[6]

Differences in project financing among independent private power developers (IPPs), public utilities and private utilities may result in different generating technologies being chosen. Public utilities, backed by sovereign guarantees, often face lower costs of capital than their private counterparts. The cost of capital for public and private utilities is based on capital structure, returns, and risks (which are diversified over the whole system). In contrast, IPPs generally must finance projects on the basis of the expected returns from the specific project. Because even well-capitalized private developers do not have the credit capacity to underwrite the debt on a portfolio of projects whose total capital costs may be several hundred million U.S. dollars, obtaining third-party debt is essential. Consequently, IPP developers face a higher cost of capital and a shorter repayment period than vertically-integrated utilities. IPP developers must recover their investment over the period of their loan repayment, which typically is about 15 years (Exhibit 3-3).

Exhibit 3-3
Ownership and the Cost of Wind Energy

The ownership and associated financial structure of wind energy projects have a significant effect on their levelized cost of energy. A U.S.-based cash flow analysis found that the most expensive ownership option is IPP ownership with project financing. Public utility ownership with project financing is slightly (1%) less expensive, while public utility ownership with internal financing is 12% less expensive, and investor-owned utility ownership with corporate financing is the least expensive option (29% less expensive than IPPs). The factors responsible for these differences are the cost of debt and equity capital, fraction of debt in the capital structure, and amortization period.[1] While the numerical results would differ, these ownership and finance structures are likely to have similar effects on the cost of renewables in developing countries.

[1] Wiser, Ryan H., "Renewable Energy Finance and Project Ownership." *Energy Policy*, Vol. 25, No. 1, 1997, pp.15-27.

These financial considerations cause private developers to prefer generation options that have relatively low capital costs per MW of installed capacity, short construction time to yield revenue quickly, high levels of efficiency, and the ability to be operated in the baseload mode. This preference may be strengthened if private developers obtain fuel adjustment clauses or government fuel price guarantees.

How the incentives facing private developers influence environmental performance (at least with respect to air emissions) than in the pre-reform state also depends on the mix of energy resources available for private power production. If available, natural gas and oil are two fuel types well-suited to private

[6] Programme for Asian Cooperation on Energy and the Environment. *Private Sector Participation in Power Generation and its Consequences on Environmental Quality.* Economic and Social Commission for Asia and the Pacific, UNDP, New York, 1995.

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developers' cost structure and short construction time. Less favored are coal, nuclear, hydro and other renewables.

In developing countries where public power systems have relied heavily on hydro, for example, private financial incentives have resulted in the increased use of thermal generation at the expense of hydro. Hydropower is usually unattractive to independent power developers because of its capital intensity and relatively long lead time. In Latin America, natural gas has often displaced hydro for new generation. In many Asian countries where natural gas is not available for power generation, coal often displaces hydro for new capacity. Both of these conditions increase air emissions from new generating units.

Hydro power has other characteristics that make it less attractive to private developers. Its site-specific characteristics make capital costs less certain than for thermal options, which are somewhat standardized. Moreover, the process for attracting bidders to hydro and thermal projects differs significantly. Issues that are specific to hydropower include site information and options for site configuration, structure of the power purchase price, and the bidding process.[7] Finally, hydro projects have traditionally included non-power benefits, such as water supply for irrigation, which may be difficult for the private sector to capture.

Power purchase agreements (PPAs) are a key component of schemes in which private developers retain ownership of the generation facility (BOO schemes). Depending on the extent to which provisions in these agreements are geared to the characteristics of environmentally-superior generation options, PPAs can either facilitate or impede efforts to develop these alternatives.

Because most IPPs have been thermal to date, the terms of standard PPAs are often geared to thermal projects. Payment terms in PPAs often create incentives for independent power producers to choose relatively low capital cost/MW generation technologies over options with comparable life cycle costs but higher capital costs. PPAs often guarantee fixed-price payments to developers over a limited period of time. IPPs, who receive private financing on the strength of PPAs, must recover capital investments over the fixed-price contract period, which is generally shorter than the facility's lifespan. This is more difficult to do for developers of capital-intensive generation options, putting them at a competitive disadvantage relative to developers of fuel cost-intensive options.

The time period of the PPA may also favor some technologies over others. PPAs are a key requirement for securing project debt finance. To attract financing, payment schedules must provide sufficient cash flows to repay loans over their terms, which may be only 5-10 years. Adequate payment schedules are particularly critical for capital-intensive power generation options, a characteristic of geothermal, wind, hydro, solar and nuclear options. Even in

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[7] Besant-Jones, John, "Guidelines for Attracting Developers of Hydropower Independent Power Projects." *Energy Note No. 9*, World Bank, Washington, DC, April 1996.

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comparing thermal technologies, a low capital cost option may be favored over one with higher capital but lower operating cost and emission rates.

Exhibit 3-4
International Environmental Guidelines

International power developers may adopt recognized environmental guidelines when future local requirements are unclear. At the same time, local environmental stakeholders may hold private power projects to international standards. Even though a project may not receive World Bank financing, its guidelines and standards are increasingly used by investors, the public, financial institutions, and some countries as the benchmark for environmental acceptability. A 1994 examination of IPP projects in developing countries found that all sponsors relied on World Bank guidelines.[1]

Guidelines covering air quality, liquid effluents, solid and hazardous waste management, and noise have been developed by such organizations as the World Bank, U.S. Ex-Im Bank, World Health Organization, European Union, and USEPA.[2] Variations among and ongoing changes in the guidelines issued by various organizations, however, may detract from their value in upgrading the power sector's environmental performance and mitigating project developers' risk. For example, World Bank guidelines for thermal power plants were recently revised after negative comments were received.[3]

[1] Baughman, David and Matthew Buresch, *Mobilizing Private Capital for the Power Sector: Experiences in Asia and Latin America.* Joint World Bank-USAID Discussion Paper, 1994.

[2] Weaver, Karen L. and George A. Schott, "The Impacts of the 1995 Financial Institution Environmental Guidelines on Power Projects." *Proceedings of the American Public Power Conference.* Chicago, 1996.

[3] Chadbourne and Parke, "World Bank Updates Thermal Power Environmental Guidelines." *Private Power Executive*, Vol. 5, No. 3, May-June 1997, p. 9.

In addition, the treatment and allocation of risks favors some technologies over others. Throughout any power project's lifecycle, the stream of costs and benefits (fuel cost and availability, construction completion date and cost, cost of capital, electricity output, maintenance, electricity demand, and environmental regulations) is more or less uncertain, giving rise to project risks. Power supply options cannot be fairly compared unless relevant risks (including environmental risks) are consistently analyzed across generation options and explicitly incorporated into decision criteria. PPAs ideally specify which party will assume different risks.

Otherwise, the project's equity owners are typically assumed to bear them. PPAs may include fuel cost indexing provisions, for example, which protect developers of thermal projects against the risk of future fuel price volatility. Although renewables are immune to fuel price risk, this advantage is ignored by developers who can shift this risk to wholesale customers.

For existing generating capacity and new projects, private owners seek ways to mitigate various risks, including the political risk that environmental regulations will be changed during the period of their ownership. Changes in environmental regulations could conceivably render a project unprofitable. Private owners of power sector assets have several options for managing such risks. One is to adopt an environmental performance standard or guideline developed by a public agency (Exhibit 3-4). Other strategies include buying

insurance,[8] adopting industry-based voluntary standards,[9] making an agreement with the host country that obligates the government to hold all laws governing their project constant throughout the entire concessional period or term of purchase agreement,[10] and drafting PPAs that allow price increases to reflect environmental compliance costs.[11]

According to a 1996 survey of power sector investors worldwide, the presence of an independent regulatory body is a requirement for investment. Both strategic and institutional investors prefer predictable rules and regulations, a stable regulatory track record, and regulatory policy with statutory authority. Environmental concerns were listed by several investors in the survey, particularly in CEE and Newly Independent States where many power sector assets to be privatized are several decades old and have high levels of emissions and accumulated waste. Investors stressed the need for a consistent environmental policy, which would allow them to factor mitigation-related capital and operating costs into the investment. Environmental laws that are strengthened after an investment may make it unviable.[12]

Different forms of private power development affect incentives for environmental performance. For example, developers of BOO projects are more likely to be concerned about future environmental restrictions than options that involve transferring the project to the government (BOOT) after a specified period of time. In the former case, developers have a greater incentive to hedge against the risk of future environmental restrictions by going beyond current environmental standards in plant design. When the project transfers after perhaps 25 years, it may have poor environmental performance, forcing the host government to incur associated costs.

Still, power projects developed by international private investors have, if anything, received more intense scrutiny than domestically developed projects. International power suppliers and investors who are sensitive to their public reputation may voluntarily adopt environmental standards that are more stringent than those required by the host country government, regardless of whether project ownership transfers back to the state.

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[8] Muncil, Robert D., "The Pollution Solution." *Independent Energy*. Vol. 27, No. 5, June 1997, pp. 36-39.

[9] MacDonald, Joseph, "Weighing ISO 14001's Benefit-Cost Value." *Private Power Executive*. Vol. 4, No. 6, November-December 1996.

[10] Chan, Michell, *Anatomy of a Deal: A Handbook on International Project Finance*. Washington, DC: Friends of the Earth, 1996.

[11] Pacudan, 1997.

[12] Hagler Bailly Consulting, "Privatization Options for the Power Industry." Prepared for USAID. March 13, 1996.

Private Investment in Energy Efficiency Measures

Privatization potentially affects the incentive of utilities and end-use customers to invest in energy efficiency measures in several ways. On the positive side, when private owners of a utility require full cost recovery and a percentage return on their investment, the price signal received by customers to use electricity efficiently is strengthened. The utility's profit motive may increase its interest in reducing peak demand to the extent that the cost of doing so is less than the cost of adding new capacity and/or running high-cost peaking plants. Moreover, to the extent price regulation perpetuates some customer cross-class subsidies, then efficiency measures targeted to reducing consumption by subsidized customers might be profitable.

On the negative side, when ownership is transferred from the public sector to the private sector, the discount rate used in making investment decisions is likely to increase. As a result, efficiency measures will yield a lower rate of return than they would under public ownership because costs are incurred in the near term while benefits accrue over a period of years. When compared to supply-side efficiency options, the set of end-use efficiency measures attractive to the utility becomes smaller.

In addition, privatization may reduce utility interest in promoting energy efficiency as social goal. However, there are few, if any, cases of developing country public utilities with significant DSM programs that have been privatized. Most countries did not invest in DSM programs before reform; thus, the impacts are still uncertain. (Thailand is considering privatizing its utility, EGAT, and the fate of its DSM programs bears watching.)

Tariff Regulation

By allocating ownership and management functions to the private sector and the regulatory function to a public agency that is independent from political pressure, the prospects for tariff reform are enhanced. Although tariff reform may be implemented as part of a commercialization package, the incentives to fully recover costs become even stronger when a private owner takes over. While tariff subsidies are common in developing countries, tariff reform does not necessarily mean price increases — depending on pre-reform customer class cross-subsidies, tariffs could go up or down.

The form of tariff regulation also affects the economic incentives of privatized utilities to undertake end-use efficiency programs. As discussed earlier, different forms of rate regulation have prevailed in different countries. The forms of rate regulation in which profits are based on total sales (price caps) create disincentives to reduce kilowatt hour sales. Under these conditions, few DSM measures other than load management are deemed cost-effective. Price cap regulation tends to discourage investments in DSM, while revenue targets offer a more neutral environment for utility-sponsored DSM. The United States and a few other countries have also experimented with other regulatory schemes designed to encourage utility investment in DSM.

CHAPTER 4
UNBUNDLING ENTERPRISES AND INTRODUCING COMPETITION

Two additional reforms, restructuring and competition, are addressed in this chapter. Each has environmental implications that are distinct from those discussed in Chapter 3.

4.1 TYPICAL REFORMS

Restructuring

This term refers to reforms that alter the organization and structure of an electric industry. In the extreme, vertically-integrated utilities are unbundled into legally and functionally distinct companies that provide separate generation, transmission, distribution and retail services. The United Kingdom (England and Wales) and Chile pioneered these models, often referred to as vertical unbundling, in the 1980s. Since then, generation, transmission, and distribution assets have been or are being separated in a number of countries, including Argentina, Bolivia, El Salvador, the Indian state of Orissa, Nicaragua, Pakistan and the Philippines. Unbundling is also popular in Eastern Europe.

Vertical unbundling is primarily undertaken to promote greater economic efficiency by creating arms-length relationships among generation, transmission and distribution entities and making each entity a potential profit center. For example, the separation of the distribution sub-sector can be used to internalize revenue losses stemming from technical and commercial energy losses. By severing managerial relationships and introducing transparent cost accounting, the distribution sub-sector's responsibility and incentive for controlling these losses becomes more clear.[1]

Country variations exist within the overall framework of unbundling. Distribution services, for example, may also be horizontally divided into separate franchises covering smaller geographic areas. In some countries, independent generators sell to a single power procurement business, which is also responsible for dispatch. Such single-buyer models are appropriate for smaller systems where the potential gains from competition are too small to offset transactions costs.[2] Also, some countries have separated electricity distribution from retail service companies, while others have kept them within the same organization.

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[1] Lewis, Piers and Dean White, *Separating Electricity Distribution: International Experience.* Prepared for U.S. Agency for International Development by Hagler Bailly Consulting, Inc., San Francisco, CA, 1995.

[2] Bacon, Robert, *Appropriate Restructuring Strategies for the Power Generation Sector: The Case of Small Systems.* Industry and Energy Department Occasional Paper No. 3. Washington, DC: The World Bank, 1995.

In countries with vertically unbundled systems, the amount a power plant is used depends on whether dispatch priorities are based on actual costs, indexed charges under long-term contracts, or on competitive bids. In Northern Ireland, for example, all dispatch is on the basis of fuel-cost indexed long-term contracts that have separate capacity and energy payments. In Argentina, plants are dispatched on the basis of energy charges. In a U.S. power pool, actual marginal costs are used to determine dispatch. Where the priority of dispatch is based on marginal costs, existing plants have an advantage over new ones. In England, Wales, and Norway, generators bid to be dispatched from a pool. For England and Wales, the pool covers 100% of the electricity traded, while only 17% is covered in Norway.[3]

Where unbundled transmission systems provide common carrier services (meaning that all generators have access to transmission lines), transmission pricing policy determines whether power developers face appropriate price signals. For example, pricing may or may not reflect local variations in the cost of service. England, Wales, Norway, and Chile use prices that reflect local cost and energy losses. In Chile, the regulated price is set for each node of the distribution network and reflects the location of electricity generation as well as marginal losses.[4]

Competition

Although the "wires" portion of the electricity sector (transmission and distribution services) is still considered a natural monopoly, competition may be introduced into the system for selling power to the grid (wholesale competition) and providing electricity to end-use customers (retail competition). For example, wholesale competition may take the form of independent power producers (IPPs), which bid for long-term contracts with power purchasers. Although there are almost as many different styles of bidding as there have been solicitations, in most cases, the utility issues a solicitation seeking bids for capacity and energy from project sponsors, with the award going to the lowest-cost supplier without regard to fuel source. The selection emphasizes the lowest fixed costs and the winning bidder receives payment sufficient to cover levelized capital and operating costs. Purchasers tend to award contracts on the basis of capacity and energy costs in the first few years of a multi-year transaction, rather than levelized life cycle costs.

As an alternative to long-term contracts, some countries (such as Chile and Argentina) are creating spot or short-term markets for wholesale power. Under this model, multiple generators bid to be dispatched by an "independent system operator" (ISO). The ISO purchaser relies on competition to ensure that bids approximate marginal costs. However, if individual generators constitute too large a share of the market, they can manipulate power output or availability to

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[3] Webb, Michael, Jamie Carstairs, and Seabron Adamson, "Power Sector Reform: Some Lessons from E&W, Scotland, Chile, and Norway." *Energy Seminars No. 16.* Washington, DC: The World Bank, August 1995.

[4] Ibid.

increase profits. Generation projects that depend on spot markets for most of their revenues are called "merchant plants" (Exhibit 4-1).

Exhibit 4-1
Merchant Plants

Merchant plants are built with the understanding that they do not have specifically- identified buyers to purchase their output at fixed prices over a long term (15-20 years). Instead, they sell into the market and receive whatever price it dictates for the particular day or hour. The incentives facing merchant plant developers with respect to choice of capital or fuel cost-intensive generation technology are different than for developers of plants with long-term sales contracts. Financing usually involves a greater percentage of sponsor equity (50% or more) than for projects with long-term contracts. This raises the cost of capital because equity capital is more expensive than debt capital.[1] Because of the uncertainty over market prices and thus investment returns, merchant plant developers are likely to opt for less capital-intensive capacity than developers of dedicated capacity. Still, the merchant plant developer wants operating costs to be sufficiently low to assure a favorable (baseload) position in the dispatch order. The tension between the developer's incentives for minimizing capital and operating costs may be resolved by choosing natural gas generation where gas supplies are cheap.

[1] Forrester, J. Paul, "Wanted: A New Financing Model for Merchant Power Plants." *Power Economics*. Vol. 1, No. 1, February 1997, pp. 23-25.

When competitive generation markets replace long-term planning for generation resources, the returns to developers may not be worth the risks of new capacity investments. To date, little new investment in generating capacity has been made on the basis of forecast spot payments from a pool. Systems that use long-term contracts between independent generators and electricity distributors provide a stronger incentive for such capital investments.[5] As practiced in the United States, the planned approach has created an obligation among electricity distributors to ensure sufficient capacity to serve the load. To offset the lack of such planning in Chile, a central government body can commission additional capacity using public funds if sufficient private capacity is not forthcoming.

In addition to these forms of wholesale competition, a few jurisdictions (i.e., Norway, England, Wales, and California) are experimenting with retail competition for some or all customer classes. Initiating retail competition is most feasible in areas where there is a significant market of industrial and large commercial customers, which are typically more attractive targets for competing firms than residential customers. Competition is often first opened up for large customers and then phased in for smaller customers over time.

Retail competition can be introduced through different mechanisms. In one, independent power generators have direct access to the transmission and distribution networks (for a charge), allowing them to compete to supply final customers regardless of their location and who owns the wires. In another model, independent retail service providers (which do not own any generation facilities) buy power from generators, contract to use transmission and distribution facilities, and sell the power to final customers. Where the distribution and retail functions

[5] Ibid.

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remain within the same entity, the service provider buys from wholesale power producers and contracts only for transmission access.

4.2 ENVIRONMENTAL IMPLICATIONS

The environmental implications of unbundling and competition depend on how these actions affect the risks, rewards, and incentives for firms operating in the reformed sector (Exhibit 4-2).

Exhibit 4-2
Environmental Implications of Unbundling and Competition

Reform	Potential Positive Impacts	Potential Negative Impacts
Competition for Supplying Wholesale Electricity	▸ spot markets create incentives for high-efficiency thermal plants ▸ profit maximization among competitive firms will create incentives to commercialize more efficient technologies	▸ spot markets and transaction costs tend to favor fossil-fueled plants ▸ if competition lowers short term prices, customer efficiency incentives are weakened ▸ the introduction of competition may lead power suppliers to cut non-critical costs, such as renewable technology commercialization
Transmission Access	▸ transmission access has potential for stimulating new renewable power generation and greater use of existing hydro capacity	▸ overall emissions may increase due to greater use of existing coal capacity ▸ renewable developers may face unfavorable contract terms for their use of transmission capacity
Unbundling	▸ the more accurately all upstream costs are reflected in the tariff structure, the stronger rural customers' incentive to invest in off-grid renewables and energy efficiency	▸ the more accurately upstream costs are reflected in the tariff structure, the weaker the retailer's incentive to invest in distributed energy
Retail Competition	▸ when generators have direct access to retail customers, they have an incentive to promote load management ▸ if the focus of competition shifts from prices to service, retail suppliers may offer energy efficiency services	▸introducing retail competition allows customers to reduce bills by shopping around, in addition to using energy more efficiently ▸ in an unbundled sector with a spot market, suppliers have little incentive to engage in DSM activities

Competition for Supplying Wholesale Electricity

From a generation developer's perspective, each competitive market model offers different risks, opportunities to manage risks, investment returns, and incentives for the choice of electric generating capacity. The environmental implications of wholesale market competition depend on the attractiveness of different generating technologies' economic and operating characteristics to developers under each market model.

In spot markets, for example, renewable generation options are less likely to be developed than in market structures with long-term contracts. Renewable projects bidding into spot markets are more difficult to finance than when they secure long-term power purchase agreements. Lenders to date have not been willing to provide debt capital for renewable energy merchant plant projects in countries where spot markets have yet to establish a track record. Capital markets prefer generation projects with low capital costs and short lead times, unless a long-term contract assures a revenue flow adequate for earning a return on principal and interest. Since private lenders require that power projects demonstrate steady, predictable cash flows to meet debt service requirements over several years, the revenue risk created by unpredictable spot markets effectively precludes financing renewable projects (multilateral development banks may offer more flexible terms).

In contrast, thermal plant developers can secure financing because they have greater control over when they sell power to the spot market (for example, by waiting to sell when demand, and thus prices, are high), and their lower debt load gives them less exposure to a prolonged slump in market prices.[6] Still, spot markets create incentives for high-efficiency thermal plants, since developers want to run their plants as much as possible to maximize returns. A natural gas-fired merchant plant being developed to compete in Argentina's power pool, for example, is using high-efficiency aeroderivative turbines.[7]

The transaction costs incurred to participate in the bidding process may also favor certain technologies. On a per-MW basis, the costs of preparing a bid for a thermal project are less than for a renewable project. The costs associated with thermal projects can be readily determined and are not particularly site-specific, allowing bids to be prepared with relatively little time and expense. Because renewable resources are site-specific, preparing a bid for the same amount of generating capacity tends to be more time-consuming and costly (although most of this work is required for financing purposes). Similarly, developers of small-scale renewable power sources may find the transaction costs of negotiating PPAs prohibitive. To address this problem,

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[6] United States Export Council for Renewable Energy, *The Renewable Energy Policy Manual,* unpublished draft, Washington, DC, 1996.

[7] Forrester J. Paul, "Wanted: A New Financing Model for Merchant Power Plants." *Power Economics.* Vol. 1, No. 1, February 1997, pp. 23-25.

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California has developed "standard offer" contract templates for small producers seeking to sell power to the grid.

One further disadvantage of spot markets for renewable generation options is that they place a high premium on generators that can assure power availability during peak periods. Because intermittent renewable resources cannot be dispatched on demand, their value is highly dependent on the rules typically governing dispatch and payment in spot markets. Returns from investing in renewable merchant plants are thus very risky, even if the output of renewable power sources is positively correlated with peak load/high-cost periods.

The introduction of wholesale competition may also affect electricity consumption and demand patterns. Retail electricity prices may drop, reflecting competition among generators who cut costs to increase their market share. At the same time, demand side management can be incorporated in wholesale markets through bidding programs, as is being tried in the Ukraine.[8]

Transmission Access

When a utility's transmission system is opened up to be a common carrier, the increased opportunity for inter-regional electricity exchanges has environmental implications. Generating units with low operating costs and whose annual capacity factors are below their operating potential could experience an increase in output. Depending on the environmental performance of such units, overall emissions may increase or decrease relative to the absence of transmission access. If the capacity factor of low-emission plants increases at the expense of high-emission plants, for example, overall system-wide emissions will decline.

Two studies of the United States power sector conclude that overall emissions will increase due to transmission access and greater consumption of lower-cost coal. In both studies, existing low-cost but relatively polluting capacity is projected to continue to generate in a competitive electricity market, perhaps at higher capacity factors.[9, 10] As mentioned in Chapter 2, similar analyses conducted for developing countries showed that the environmental results of transmission access depend on the mix of generation resources available.

In addition to affecting the use of existing generation, transmission access has the potential for stimulating new renewable power generation. Because renewable resources are location-specific, renewable power generation developers are especially dependent on access to transmission lines.

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[8] Wolcott, David. Personal communication. January, 1998.

[9] Biewald, Bruce, "Competition and Clean Air: The Operating Economics of Electricity Generation." *The Electricity Journal.* Jan./Feb. 1997, pp. 41-45.

[10] Lee, Henry, and Negeen Darani, *Electricity Restructuring and the Environment.* Cambridge, MA: Center for Business and Government, John F. Kennedy School of Government, Harvard University, December 1995.

Transmission access gives these developers the ability to sell power to locations where, and at times when, it is more highly valued than by the local utility.

Despite legal and physical access to transmission lines, however, renewable developers may face unfavorable contract terms for their use of transmission capacity. Developers of intermittent generation may be charged more per kWh to transmit power than their dispatchable competitors if access charges are based on a generator's maximum rated capacity rather than what it actually generates during peak periods. Moreover, the site-specific nature of renewables may be a drawback under some transmission pricing schemes. Rates may be based on distance or contract paths, regardless of the actual costs associated with the flow of electrons.

Distributed Resources

Distributed resources help avoid investments in generation, transmission, and distribution infrastructure needed to meet peak demand. When a vertically integrated utility becomes unbundled, the deployment of distributed

Exhibit 4-3
Cost Allocation in Unbundled Power Sectors

Unbundling affects the treatment of demand-related costs. Distributing resources helps diminish the necessity of investments in generation, transmission, and distribution infrastructure to meet peak demand. When generation is separated from retail functions, generation investment costs are no longer controllable by retail suppliers. Avoidable demand-related costs are further reduced if the retailing function is also unbundled from T&D services. Retail suppliers are likely to pay a premium for power acquired for resale during peak demand periods.

At one extreme, customers could see fully unbundled rates based on area- and time-specific energy, transmission system capacity, and distribution capacity costs. Depending on the previous rate structure, such rates could improve ratepayers' economic incentives for managing their demand and reducing consumption. A key factor is whether regulators allow retail suppliers to charge time- and area-specific rates. (Regulators may also allow retailers to pass through fuel cost adjustments.) The cost of installing time-of-use meters, especially for small customers, also affects whether demand-related costs are passed on directly.

At the other extreme, retailers would roll demand-related costs into fixed charges or energy charges, in which case they themselves would have stronger incentives to manage customer load. Combined distribution and retail supply companies would be particularly sensitive to reducing load in locations where the marginal costs of service are high due to network constraints, inefficient use of distribution assets or other reasons. (So-called "performance-based rate-making" can create incentives for retail suppliers to profit from demand-side investments that reduce distribution system costs.) To the extent that unbundling causes total bills to shift toward greater fixed cost components, the potential bill savings to customers from making energy efficiency investments are reduced.

resources[11] depends on their net benefits to a potential investor in the unbundled sector (generators, wholesale customers, retail service providers, or even retail customers), not on their overall benefits to the system. How an unbundled power sector operates affects the market value of distributed resources and the incentive of potential investors to develop them. When generation is separated from retail functions, for example, generation investment costs are no longer controllable by retail suppliers. Avoidable demand-related costs are further reduced if the retailing function is also unbundled from transmission and distribution services. (See Exhibit 4-3).

Cost allocation rules must enable some entity to identify, value, and capture their avoided generation, transmission, distribution, and fuel costs. When a privatized, vertically-integrated utility is unbundled into separate firms, the actual costs of providing generation, transmission, distribution, and retail services may not change but each cost becomes assessed differently. Whether unbundling results in stronger or weaker incentives to deploy distributed resources depends on how these costs are allocated among various market actors. In general, the more accurately various upstream costs are reflected in the tariff structure, the weaker is the retailer's incentive and the stronger the customer's to invest in distributed resources.

Unbundling also affects how rural electrification is carried out. In many countries, the distribution monopoly has been privatized and unbundled from power generation. The national or state government may grant the new private owner(s) a long-term concession for the right to distribute electricity to a defined geographic area that includes both urban and rural customers. While the distribution company can extend the grid, it may or may not have the authority or expertise to pursue other means of providing electricity services to rural areas.

Several countries in Latin America are pioneering approaches to use private distribution companies as a deployment mechanism for renewable power generation. Argentina is implementing a "rural concessions" program (see Chapter 6). Brazil's government is considering a similar concept in at least three states.[12] The Bolivian government requires that all distribution companies enter into long-term contracts for 80% of their projected load. In order to encourage renewables, the law allows distribution companies to own generation facilities for up to 15% of projected load and specifies that any generation facility owned by a distribution company must be based on a renewable resource.

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[11] Distributed resources include small-scale renewable, end-use efficiency, or even efficient fossil generation strategically located near high-cost areas of end use. As discussed in Chapter 2, the potential grid-support benefits from strategically-located distributed resources may exceed their generation benefits.

[12] Kozloff, Keith, *Deploying Renewable Energy Systems for Rural Electrification in Brazil: An Evaluation of Alternative Mechanisms.* Arlington, VA: Hagler Bailly Services, 1997.

End-Use Efficiency[13]

The effect that unbundling has on incentives to promote end-use efficiency is similar to that for other distributed resources. That is, the more closely retail electric bills reflect costs of service, the stronger the signals the customer receives to undertake energy saving measures (Exhibit 4-3).

The net effect of introducing wholesale competition on adoption of energy efficiency measures is negative (although such competition may result in economic benefits due to lower electricity prices). Wholesale competition, particularly in spot markets, tends to reduce near term costs and makes future prices less certain. Electricity users' dollar savings over the life of energy saving measures become more risky when volatile spot markets and resulting variability in future electricity bills make these savings more uncertain. Under such conditions, end users would be expected to discount future benefits more heavily than when electric bills are expected to remain relatively stable.[14]

Introducing retail competition to a fully unbundled power sector generally increases the retail supplier's incentive to maximize kilowatt hour sales up to the point where marginal costs equal marginal revenues. Whether retail competition is introduced to a vertically-integrated or unbundled model, in both cases electricity suppliers become concerned with having the lowest rates to retain and attract customers. In the case of an unbundled sector with a spot market, independent competitive retailers pass generation costs through to final customers. Under such scenarios, electricity suppliers have little incentive to engage in any DSM activities that raise rates to non-captive customers. In such cases, the non-captive customers are likely to simply switch suppliers. In countries that had utility-sponsored DSM prior to unbundling, retail

[13] For a more detailed discussion of these issues, see Hagler Bailly Services, Inc., *Promoting Energy Efficiency in Reforming Electricity Markets: A Guidebook for Stakeholders.* Prepared for USAID, Center for Environment. Arlington, VA: October 1997.

[14] In the United Kingdom, many larger end-users and some retail suppliers sign long-term delivery contracts to ensure rate stability, despite the spot market.

competition has generally caused a withering of such efforts and has not been replaced by other mechanisms to promote energy efficiency.[15, 16, 17, 18]

Still, other combinations of unbundling and retail competition could conceivably stimulate power sector-sponsored DSM. For example, when generation companies have direct access to retail customers, they have, at a minimum, an incentive to maximize their generation units' capacity factors, which they can promote through load management, often a component of DSM programs.

In addition, when the price/kWh is close among competitors, retailers may find it profitable to retain or attract customers by offering a package of DSM services as a means of differentiating themselves from competing suppliers, even though DSM may dampen sales. This conclusion has not yet been borne out by experience, however, in countries which have already established competitive markets. Under these conditions, DSM measures being offered are likely to be different than if offered by a noncompetitive vertically-integrated utility. To retain large customers, who tend to be the most mobile, retail suppliers may offer customized energy management services that combine fuel switching, load management, energy conservation, and other services that may increase or reduce total kWh sales. Less likely are small-scale residential programs.

From the end users' perspective, introducing retail competition affects efficiency incentives in several ways. First, overall prices may decline. If retail electricity prices increase, however, (which could be the case in countries where prices were heavily subsidized prior to reform), incentives for end-use efficiency will increase. Partial retail competition (such as competition for large customers) may create incentives for the retail supplier to shift some costs onto captive customers, within regulatory constraints, in order to remain competitive with open-access customers. Efficiency incentives could thus be strengthened for small customers and weakened for larger ones.

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[15] York, Dan, "Are Deregulation and Integrated Resource Planning Compatible? Experience from the United States and Norway with Market Approaches to Utility Planning." *ECEEE Summer Study: The Energy Efficiency Challenge for Europe*, Copenhagen, 1993, pp. 237-249.

[16] Nadel, Steve, *The Impact of Energy Sector Restructuring on Energy Consumption and the Environment: International Experiences.* Washington, DC: American Council for an Energy Efficient Economy, January 1996.

[17] King, Michael, Grayson Heffner, Stale Johansen, and Brian Kick, "Public Purpose Energy Efficiency Programs and Utilities in Restructured Markets." *The Electricity Journal,* July 1996, pp. 15-25.

[18] Hoch, Lance and Linton Parker, *Sustainable Energy in Competitive Electricity Markets: What's Been Tried, What Works, and What Doesn't.* SRC International, n.d.

Second, customers that previously had only one way to reduce bills (reduce consumption or load) now have the additional and perhaps easier option of shopping around for a lower-cost supplier. The competing and often confusing claims of various suppliers regarding rates and special services they are marketing may also reduce interest in making efficiency improvements.

Retail competition may stimulate the emergence of ESCOs that market both electricity supply and demand management to serve non-captive customers who want to optimize their combination of end-use services and total electricity costs. To the extent that customers in a competitive market want to reduce their bills but are confused as to how to do so, ESCOs could prosper. To date, however, there is little evidence that such a market is emerging in countries with retail competition.

Technology Commercialization

The advent of competition may change the incentives facing the power sector to invest in commercializing certain technologies. Profit-maximization among competitive firms will create incentives to commercialize technologies that improve the efficiency of generation, transmission, distribution or end use, where efficiency gains can be captured by investors. When competition is introduced, power suppliers may cut costs for noncritical services, including long-term technology development. In the United States, utility research programs have shrunk in anticipation of competition and have been redirected toward priorities dictated by this competition.[19] It is not clear which actor in a competitive power market will have the incentive to conduct research and development and other commercialization activities for environmentally-friendly but relatively unfamiliar energy options that do not yield near-term economic benefits or whose benefits cannot be captured by the individual players.

[19] Kozloff, Keith, "Power to Choose: Sustainability in the Evolving Electricity Industry." *Frontiers of Sustainability.* Washington, DC: Island Press, 1997.

CHAPTER 5
POWER SECTOR REFORMS IN THE UNITED KINGDOM

The purpose of the next three chapters is to discuss the reforms of three specific countries, in order to extract important lessons learned about environmental implications from their experiences. Each chapter will follow a similar format, outlining specific power sector characteristics and reforms undertaken, environmental policy and legislation in place prior to or during reform, and the effects of the reforms on the environment in each country. These sections are followed by conclusions about the relevance of each country's experience to developing country conditions and reform processes.

5.1 POWER SECTOR CHARACTERISTICS AND REFORMS[1]

The United Kingdom (UK) is one of the world's leading economies. The UK has large coal, natural gas, and oil reserves, and primary energy production accounts for 12% of GDP (one of the highest shares of any industrialized nation).[2] In the 1980s the UK began deregulating and privatizing its state-owned industries, including power, natural gas, and telecommunications, making it one of the first nations to undertake such reforms.

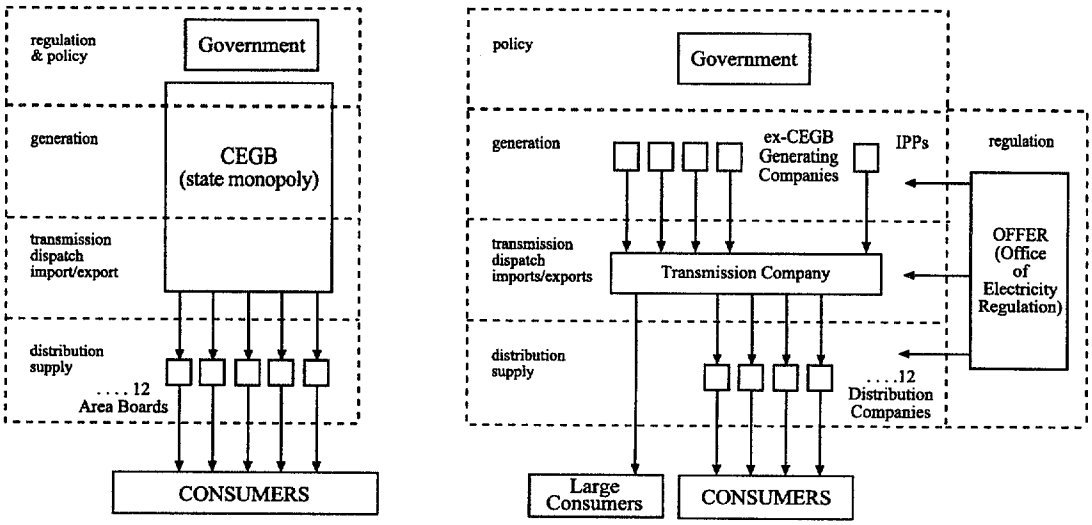
Before the reforms, the UK electric system was wholly government-owned and vertically-integrated (the Central Electricity Generating Board or CEGB), with a national grid for transmission dispatch and 12 area distribution boards. The 1989 Electricity Act provided for a complete reform of the industry, with the objectives of 1) reducing the government's role by fostering private ownership, management, and competition, leading to increased operating efficiencies, and 2) maximizing public revenues through privatization. Privatization was a key part of the overall reform; however, the political decisions on restructuring were made when the industry was still government owned.

Restructuring and Privatization
CEGB was broken into two fossil-fuel based generating companies (PowerGen and National Power), a state-owned company encompassing the nuclear plants, and the National Grid Company, which took over the transmission business and dispatch function. The structure of

[1] The UK has three separate electricity supply systems. The England/ Wales system is described here; those of Scotland and Northern Ireland were also privatized, but using models with much less emphasis on competition.

[2] *CIA World Factbook, 1996/97.*

Exhibit 5-1
U.K. Power Sector Before and After Reform



Power Sector Ownership: Public

Power Sector Ownership: Public & Private

the12 area boards was maintained and they became the Regional Electricity Companies (RECs). The government began selling shares in the 12 RECs in 1990 and subsequently privatized PowerGen, National Power, the Scottish and North Ireland utilities, the National Grid Company and part of the nuclear capacity (Exhibit 5-1).

The government initially retained the right to veto REC takeovers (the "golden shares"). Since these shares expired in March 1995, 11 of the 12 RECs have been bought by other utilities (including several U.S. and European utilities as well as two water companies). Although the final outcome of these ownership changes is not clear, the industry could become dominated by a handful of vertically integrated generation and supply companies combined with horizontally integrated (electricity - water - gas) utilities.[3]

Wholesale Competition

The National Grid Company is responsible for operating the new Power Pool, which establishes dispatch, conducts transmission planning, and constructs transmission lines. All generators must declare their capacity availability and bid prices at half-hour intervals. All generators that provide power for the same half-hour are paid the pool's highest accepted bid price for that period, regardless of their operating costs or bid price. The National Grid Company provides a one-day

[3] Brower, M., S. Thomas, and C. Mitchell, "Lessons from the British Restructuring Experience." *Electricity Journal*, Vol. 10, No. 3, April 1997, pp. 40-51.

forecast of demand for each half-hour on which generators base their bids. It then determines the merit order (the order of dispatch ranked by bid price) and the price to be paid to generators. Pool prices have been extremely volatile and unpredictable. Many observers suspect they have been manipulated by NationalPower and PowerGen, whose power plants determine the pool price about 85% of the time.

Although all electricity must be sold through the pool, about 80% of sales involve bilateral long-term contracts that eliminate or reduce the effect of the pool price on the actual prices paid. In these "contracts for differences" (CFDs), buyers and sellers agree to pay each other the difference between the predetermined contract price and the pool price. Only one large industrial customer has opted to buy power directly from the pool rather than through bilateral contracts.

Retail Rate Regulation

The Office of Electricity Regulation (OFFER) regulates England, Scotland, and Wales' transmission and distribution (T&D) networks, and the supply function for the franchise market (customers with less then 100 kW demand) under a system of performance-based regulation. Prices are set according to the "RPI minus X" formula, in which RPI is the real price index and X a productivity factor, which is determined based on estimated productivity increases in the industry. The regulatory formulas for T&D are controversial because the RECs seem to reap overly high profits (their average operating margin rose from 8.2% to 13.4% and dividends per share more than doubled from 1991 to 1995).[4] Effectively, the performance-based system has evolved into a process in which the X factors are calculated by reference to an implicit, target rate-of-return, effectively moving the regulatory regime back in the direction of rate-of-return regulation.[5]

According to OFFER, the average real (inflation adjusted) prices excluding VAT for domestic and industrial customers fell by 15% to 21% for industry between 1990 and 1996.[6] Some critics point out that this decrease is rather modest as prices actually increased in the pre-restructuring period from 1987 to 1989 and plant fuel prices decreased significantly since restructuring began.

Retail Competition

A key feature of the liberalization in England and Wales is the phased introduction of competition. Since 1990 about 5,000 customers with a maximum demand of over 1 MW have become eligible to buy power from any REC, licensed supplier, or directly from the pool. The

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[4] *The Benefits and Deficiencies of Energy Sector Liberalization - Case Study: The United Kingdom.* Draft report prepared for the World Energy Council, November 1996.

[5] Brower et al, op. cit., and Bacon, Robert, "Lessons from Power Sector Reform in England and Wales." IEN Note No. 61. World Bank, October 1995.

[6] *OFFER Annual Report 1996*, June 1997, p. 37.

RECs retained a regulated monopoly to serve non-eligible franchise customers while providing non-discriminatory distribution access within their service territory. In 1994, some 45,000 new customers with demands over 100 kW became eligible for supply choice. Complete retail competition for all 22 million customers will phased in between April and September 1998. OFFER plans to introduce supply price restraints (i.e., a price limit for domestic customers that don't switch their supplier) for the first two years of retail competition.[7] The RECs are expecting a slump in profits due to higher advertising and customer service costs combined with competitive pressures. Supply is already a competitive business with low margins (1% to 3%).

Many companies are forming supply subsidiaries and alliances to prepare for retail competition. For example, talks about an alliance between United Utilities and British Telecom (BT) to market energy to BT's customers have been reported. Also, the Trade Union Congress has started a power marketing company to arrange favorable deals for its members once retail competition begins. The bundling of several utility services such as water, gas and electricity is restricted by rulings stating that the customer must be able to terminate each service individually. It is thus unclear whether residential customers will see a significant benefit from retail competition.[8]

5.2 ENVIRONMENTAL POLICY AND LEGISLATION

British environmental policy has undergone major changes in the 1990s, largely as a result of European economic unification.

Environmental Laws

The three main pieces of UK environmental legislation relevant to air pollution are:

- **Environmental Protection Act** (1990). Part I of the Act establishes that all major pollution sources are regulated (through a permitting procedure) by the Environment Agency for England and Wales and its counterparts in Scotland and Northern Ireland. Small pollution sources are regulated by local authorities.

- **Clean Air Act** (1993). This Act consolidates amendments to the Clean Air Acts of 1956, 1968, and 1969. It covers only combustion processes and emissions of smoke, grit, and dust. Under the 1993 Act, the central government can set emission limits and ambient air quality standards nationwide.

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[7] Office of Electricity Regulation (OFFER), *The Competitive Electricity Market from 1998: Price Restraints - Fourth Consultation*, July 1997.

[8] Thomas, Steve, "Electric Reform in Great Britain: An Imperfect Model." *Public Utilities Fortnightly*, June 15, 1996, pp. 20-24.

- **Environment Act** (1995). The Act requires the preparation of a National Air Quality Strategy, with air quality standards to be achieved by environmental agencies and local authorities. It also establishes separate environmental agencies for England and Wales, Scotland, and Northern Ireland.

UK national legislation and air quality regulations are required to comply with EU regulations. EU Directive 80/779 of 1980 sets ambient standards for SO_2 and suspended particulates. Directive 85/203 sets an ambient air quality standard of 0.2 mg/m^3 for NO_x. To comply with these directives, Great Britain enacted new Air Quality Standards in 1989, the first such mandatory standards in the UK. A recent EC interpretation, which has been accepted by the UK, has significantly widened the directives' potential effects. They now apply not only to emissions from combustion but also to particulate emissions from other sources, including open-cast coal mining.

EC Directive 88/609 of 1988 is designed to limit emissions of SO_2, NO_x, and dust from fossil-fueled power stations with thermal output of 50 MW or more and other large combustion plants such as oil refineries. Gas-powered plants are exempted. Existing plants are subject to total national emission limits with phased reductions and with different limits for individual member states. Emission limits for new plants are set according to individual permits: emissions from plants of more than 300 MW must be measured "continuously" and from other plants "regularly." Annual SO_2 and NO_x emission inventories must be submitted to the EC on a plant-by-plant basis for power plants over 300 MW, and on an overall basis for other plants.

The UK national plan adopted in compliance with Directive 88/609 requires SO_2 emissions to be reduced by 20% by 1993, 40% by 1998, and 60% by 2003, compared with 1980 levels. NO_x targets call for a 16% reduction by 1993 and 31% by 1998. These reduction targets are very modest compared to other EU countries such as Germany, whose 1983 national air emission standards forced utilities to reduce SO_2 emissions by 90% and NO_x emissions by 66% compared to 1982 levels.[9]

UK air pollution regulations are based on a command-and-control approach and the use of economic instruments is insignificant. Generators have an overall emission quota based on the "bubble concept"(in which cumulative emissions from all sources within a defined areas are capped). Limits are set annually for each plant within a bubble. There is some flexibility for trade-offs among sources within a bubble, but no formal trading of permits is allowed between companies.

[9] IZE (Information Center of German Utility Industry), "Vom Wirkungsgrad zur Energievernunft" (From Conservation Efficiency to Energy Savings). Frankfurt, no publication date (probably 1995/96), p. 13.

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The UK also ratified the Framework Convention on Climate Change in 1993. In 1994 it published *Climate Change: The UK Programme*, which declared an objective to return emissions of carbon dioxide and other greenhouse gases to their 1990 levels by the year 2000.[10]

5.3 ENVIRONMENTAL EFFECTS OF REFORMS

Generation Mix

In 1994, roughly 50% of the UK's capacity was based on coal, 15% was new combined cycle natural gas plants (with a further 2.3 GW under construction) and 28% was based on nuclear units. Renewable sources, primarily large-scale hydro facilities in Scotland, accounted for about 1.4% of electricity generation.

Before privatization, the UK's new generation plans were for three large coal-fired stations and three nuclear stations. Its pre-reform generation portfolio was influenced by government policies that had social objectives other than economic efficiency. For example, the use of British coal at above-world market prices was mandated. In addition, until the late 1980s, burning natural gas in large power plants was prohibited by an EU directive to ensure sufficient supply for industrial, commercial, and residential use. Last, nuclear power remains largely a government enterprise since the government has been unable to find private buyers for the older plants.

Since reform, plans for new coal and nuclear capacity have been replaced by natural gas-fired combined cycle generation, and there has been a significant reduction in domestic coal subsidies. The International Energy Agency estimates a reduction from $70.6 per tonne of coal produced in 1988/98 to $5.7 in 1993/94. However, the subsidy reduction is not directly attributable to reforms. (In order to prevent a sudden collapse of the domestic coal industry, generators were required to buy coal at above world market prices from British Coal until 1998. Generators then pass on the additional costs to RECs via government-brokered CFDs.)

Once the prohibition on burning natural gas for power generation was lifted, there was a "dash for gas" by generation companies and IPPs (which are often owned by RECs) under long-term contracts with the RECs. A number of highly efficient combined cycle gas-fired plants have been built that rely on long-term contracts with low-priced natural gas from the North Sea.

The Power Pool must purchase uncompetitive nuclear power through the Non-Fossil Fuel Obligation (NFFO). Under the NFFO, RECs must buy minimum quantities of electricity from nuclear and renewable sources (the share of funds spent on renewables increased from 1% in 1990 to 9% in 1995-96). The extra cost is spread across customers through an initial levy on all accounts of 10% of the electricity price. Since the partial privatization of the nuclear power

[10] Institute for European Environmental Policy, *Manual of Environmental Policy: the EC and Britain*, London, 1996.

plants in 1996, the government decided to stop payments to nuclear generation, and the levy has been reduced to 2.4% in England and Wales.[11]

The NFFO had a strong positive impact on the development of the UK market for renewables. Contracts for 1,250 MW of declared net capacity were awarded until 1995, encompassing hydro, wind, biomass, waste-to-energy (several hundred MW), landfill gas and sewage gas projects. A fourth round in 1996 resulted in a price drop of about 30%, with 843 MW ordered by the government in February 1997. A fifth round of bidding is expected to lead to a further 400 to 500 MW of contracts 1998. The government aims to have 1,500 MW of renewables operating by the year 2000. The average costs of bid electricity have fallen from 11.7 cents/kWh in 1991 to 7.1 cents/kWh in 1994 to 5.6 cents/kWh in 1995.[12] The price drop, however, may be due to a relaxation of the short, eight-year contract period that was imposed on the first two solicitations.[13] Critics also point out that competitive bidding combined with the NFFO has disadvantages compared to the method employed in Germany, Denmark and Netherlands where renewable electricity is paid a standard pre-known payment per kWh.[14]

While the introduction of the NFFO has had a positive impact on the development of renewable energy, many observers see this more as a byproduct of the support for nuclear industries rather than a conscious policy decision. There are no plans for further NFFO renewable energy orders after 1998, making further renewables development uncertain in the absence of support.

In the short run, capacity mix changes have resulted in lower air emissions than if the pre-reform regime had continued. In February 1997, Environment Minister John Gummer declared that he expected Britain's CO_2 emissions to be 4 to 8% percent below 1990 levels by the year 2000.[15] This appears to be largely the result of the switch from coal and oil to natural gas. However, the retirement of uneconomic nuclear capacity could substantially increase the need for thermal generation in a few years. While natural gas is the current fuel of choice, over the long run coal is likely to be used as well.

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[11] Hamrin, Jan, with William Marcus, Fred Morse, and Carl Weinberg, *Affected with the Public Interest: Electric Utility Restructuring in an Era of Competition*. National Association of Regulatory Utility Commissioners, 1994.

[12] "U.K.'s Fourth NFFO for up to 500 MW Draws 890 Bids Total 8,397 MW." *Independent Power Report,* March 22, 1996.

[13] Wiser, Ron and Steven Pickle, *Financing Investments in Renewable Energy: The Role of Policy Design and Restructuring*. Berkeley, CA: Lawrence Berkeley National Laboratory, March 1997, p. 31.

[14] Lowry, David,"Power for Million-Plus Homes Seen in England, Wales from NFFO." *The Solar Letter*, Vol. 7, No. 5, 1997, p. 88.

[15] "UK Expects to Exceed Rio Target for CO2 Emission," Reuters North American Wire, February 18, 1997.

Environmental Controls

Because the Environmental Protection Act's implementation (1991 for new large combustion plants and 1996 for existing plants) closely coincided with power sector liberalization, market forces have affected how environmental policy has been implemented. The UK initially planned to comply with EC SO_2 reduction targets by installing flue-gas desulfurization (FGD) equipment on 12,000 MW of capacity, but privatization disrupted these plans. First, FGD equipment costs were large enough to jeopardize the attractiveness of selling the existing generating companies. Second, the EC indicated its intention to relax its prohibition on burning gas in power stations. Given the economic attractiveness of gas, both the two main generators and the new independent generators planned to build gas-fired generation.

The market thus dictated that switching to gas would be a more cost-effective way to reduce SO_2 than stack controls. However, this option was limited for the first three years after privatization, because the government imposed a high-volume contract between British Coal and the generators. As a result, the FGD commitment was only scaled down to 8,000 MW instead of being dropped. Almost all small and medium sized coal-fired power plants have now been retired and large coal plants have been forced into intermediate load by the new natural gas plants and increased nuclear output. The UK thus achieved the SO_2 target reductions for 1993 through the "dash for gas" in the wake of power sector privatization.

The UK's privatization process also constrained the use of economic incentives, such as taxes, to control pollution.[16] The EC has been promoting the use of such incentives; however, the British Government was instrumental in blocking an EU-wide carbon tax, which it saw as an infringement of national sovereignty.[17] According to one observer, another reason for opposing the tax was concern over jeopardizing the sale of the electricity industry.[18] If so, the Government gave privatization higher priority than environmental policy when the two clashed.

Transmission and Distribution Services

In the UK's unbundled market, T&D companies transport power from the generator to the end-user without taking title to it. Initially, these companies could pass through any costs associated with T&D losses and thus had little incentive to invest in loss-reducing equipment. To offset this, if a distributor in England or Wales improves its losses over an OFFER-set baseline index, it earns an incentive at a fixed value of energy; if it realizes losses in excess of the index, it is penalized at the same rate. With respect to end-use efficiency, the National Grid Company could

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[16] Helm, Dieter, "Privatization and Environmental Regulation in the Water and Electricity Industries." *The Royal Bank of Scotland Review*, No. 172, December 1991, pp. 31-37.

[17] Boulton, Leyla, "Red Lights Block Green Taxation." *The Financial Times*, 11/11/96, p. 02.

[18] Muller, Frank, "Mitigating Climate Change: The Case for Energy Taxes," *Environment*, Vol. 38, No. 2, March 1996, p. 12ff.

undertake conservation activities to avoid transmission investment, but its limited end-user contact and the large and "lumpy" nature of transmission investment reduce any incentive to pursue end-use conservation.

End-Use Efficiency Measures

Overall, the UK reforms have had an adverse effect on end-use energy efficiency due to falling electricity prices and an absence of utility incentives. The regulatory formula encourages suppliers to sell as much power as possible.[19] Supply costs are passed through to consumers in full; there is no incentive to reduce them through DSM and no ability to raise rates to recover DSM costs or lost revenues.

In the competitive market above 100 kW, customers appear to choose their supplier based far more on price than energy services. There are some ESCOs (called contract energy management companies in the UK) active in the industrial and commercial market segments, but their services focus primarily on arranging for the cheapest power supply. Energy cost reduction via performance contracting plays only a secondary role. Furthermore, electric and gas utilities that own ESCOs lack incentives to earn money by reducing the demand for their own product. Instead, they see ESCOs as a strategic weapon for retaining customers or gaining access to new customers when a customer asks for an integrated energy solution.

There was little public sector activity with performance contracting for third-party financing (TPF) of energy efficiency retrofits until 1990 when new guidelines allowed investments of up to $375,000 under TPF contracts without Treasury approval. Nevertheless, complex procurement procedures have slowed progress. Under the "public-private partnership initiative," the Department of Environment is trying to improve the market for energy services in public buildings.

OFFER found significant energy efficiency potential in England and Scotland, and considered instituting a large wires charge to fund efficiency programs. This approach was eventually rejected, however, because OFFER felt it would exceed its mandate. Instead, a modest $1.62 annual fee per account was implemented in the franchise market (i.e., customers with demand <100 kW) to fund energy efficiency programs for 1994 to 1998. This fee equates to about 0.25% of REC revenues (the U.S. average for DSM expenditures is 1% to 2% of utility revenue). OFFER has also changed the regulatory formula to allow about 50% of the revenues under the formula to be collected through fixed charges. As a result, the volume incentive has been reduced. Observers hope that some retail supply companies might use energy efficiency as a means to differentiate themselves after the introduction of full retail competition in 1998.

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[19] de Oliveira, Adilson and Gordon MacKerron, "Is the World Bank Approach to Structural Reform Supported by the Experience of Electricity Privatization in the UK?" *Energy Policy*, Vol. 20, No. 2, Feb. 1992, pp. 153-162.

The annual fee will be collected until March 1998 and generate $165 million. This compares to the $1.62 billion 1994-2000 budget the Energy Saving Trust (EST, see below) was planning for in 1992. OFFER administers these funds and has established Standards of Performance requiring RECs to achieve certain energy savings through a variety of DSM and low-income programs. The EST oversees program design and implementation by the RECs. In the first two years of its operation, $6.5 million has been spent under the Standards of Performance program resulting in estimated lifetime savings of 3,000 GWh. The program costs per kWh saved are estimated at 2.19 cents/kWh; the costs to all parties of saving energy (including additional costs by the program participants) are estimated at 2.72 cents/kWh, significantly lower than the RECs' cost to purchase electricity: approximately 6.16 cents/kWh.[20]

The EST was established in 1992 to help stabilize the UK's CO_2 emissions. It developed a comprehensive plan for energy efficiency measures in which funding would be provided through gas and electric levies. However, neither OFFER nor OFGAS (the natural gas regulator) felt that the extent of funding proposed was within their authority. This decision effectively limited EST's activities to implementing market transformation programs and overseeing OFFER's Standards of Performance programs.

The Department of the Environment announced funding of $113 million for 1996 to 1999. Its activities include the creation of 35 local energy advice centers, school energy efficiency programs, ESCO promotion/pilot projects, small-scale cogeneration, a nationwide marketing campaign for energy efficiency, the promotion of alternative fuel vehicles, and several energy efficiency rebate programs.[21]

Several RECs have used shareholder and EST funds to defer investment in distribution upgrades. REC economic evaluations consider avoided distribution upgrade investment costs versus energy savings program costs *plus* the foregone profits of additional transport revenue. This evaluation strongly limits the energy efficiency potential that is attractive for the REC. OFFER is planning to extend the Standards of Performance program and the funding mechanism for two more years as part of the planned introduction of price restraints for residential customers.

OFFER did not believe that there was sufficient reason for intervening in the non-franchise market and feels that a competitive energy services industry should be given sufficient time to develop. There is some evidence that this is happening. Interruptible/curtailable tariff options have been developed between suppliers and large end-users. If the end-users have a fixed-price contract, suppliers try to mitigate their pool price risk by integrating load management features

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[20] Energy Saving Trust, *Energy Efficiency Standard of Performance for England, Wales and Scotland, 1995/96*, August 1996.

[21] Energy Saving Trust Schemes, *Changing Attitudes to Energy Efficiency,*" March 1997.

into their contracts. In addition, a limited demand bidding pilot has operated in England and Wales for some years.

Technology Commercialization

Investment in commercializing environmentally-friendly supply- and demand-side technologies has been reduced the wake of restructuring. Power sector-funded RD&D has fallen from a high of 1.4% of revenues in 1988-89 to 1% today. Research now focuses on ways to improve profitability and is conducted on a proprietary basis because of the highly competitive market.[22] Exceptions are increased investments in combined heat and power projects (due to a relaxation of controls on autogeneration as part of the restructuring process), investments by RECs in more sophisticated end-use metering and control equipment for the commercial and industrial markets, and the investments in renewable power generation.[23] Also, the prospect of power sector deregulation and sales to gas powered generation may have stimulated investment in natural gas production and transmission capacity.

5.4 CONCLUSIONS

The key parameters influencing the positive and negative environmental effects of the UK power sector since the beginning of its reform include:

- the decisive move from coal-fired power plants to new and highly efficient natural gas power plants, resulting in reduced emissions
- the reduction of nominal and real electricity prices combined with the perception of ever falling prices, resulting in reduced end-user investments in energy efficiency measures
- the introduction of more stringent environmental legislation for power plant emissions as well as for building and appliance energy efficiency
- the introduction of the NFFO, resulting in a significant increase in renewable energy capacity (however, it remains small compared to absolute capacity)
- the creation of the Energy Savings Trust to oversee and conduct energy efficiency programs and campaigns

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[22] Hamrin et al. , op. cit., 1994.

[23] Swinden, D.J., "Energy Efficiency and DSM in a Fully Competitive Market." Presented at 3rd International Energy Efficiency and DSM Conference, Vancouver, November 1994.

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- an increased incentive for the now privately operating utilities to maximize electricity sales and a disincentive to conduct DSM-type programs

- an increased incentive for utilities to optimize operational and technical efficiency in electricity generation, transmission and distribution due to their profit motive.

Although the magnitude of each effect on the environment is difficult to quantify, the move from coal to gas is critical. The second and third effects also appear very important relative to the fourth to seventh. The last does not appear to be very important, as the UK's power system did not suffer from high losses or non-collection rates before privatization.

It should be noted that the move from coal to natural gas as well as the introduction of new environmental regulations are not directly related to power sector reform but a result of several factors. The move to natural gas was aided by: its abundance and low cost since the early 1990s; a parallel relaxation of guidelines on the use of gas in power plants; environmental regulations; reductions in coal subsidies; and by the strategic advantages of easy-to-build natural gas plants for RECs.[24]

Several important conclusions for developing countries can be drawn from the UK experience:[25]

- The availability and price of natural gas are likely to have major influence on power plants' environmental effects because gas-fired power plants are preferred by investors due to their low capital costs and short construction times.

- Power plant emission standards (and their enforcement) are a key factor in determining the environmental performance of the power sector regardless of its organization, structure or regulatory model.

- Under the regulatory model pursued in the UK, creating competition, fair prices and (at least some) incentives that are sufficient for utilities to conduct distribution and end-use energy efficiency investments requires complex rules and a strong, independent regulator. Implementing the "right" regulation under a performance-based regulatory system has proven to be a complicated, lengthy, and highly information-intensive process.

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[24] The RECs decided to build power plants within a short period of time so they would not be entirely dependent on the dominant generators, PowerGen and NationalPower.

[25] The UK's power system is atypical of the situation in developing countries — it is much larger than most developing country systems (68,000 MW versus usually only several thousand MW), has comprehensive coverage in rural areas, has little growth in demand, and had overcapacity at the time of reform. In contrast, power sectors in many developing countries are growing rapidly due to both increased demand in urban areas and extension of the grid into the countryside.

- In a competitive market, the focus of energy service offerings to industrial and commercial customers is on finding the cheapest supplier; energy efficiency services and performance contracting is a niche product at best and does not substitute for a comprehensive government energy efficiency policy.

- During the reform process, clear provisions must be made for the funding mechanism, amount of money committed, and time period of energy efficiency programs. Otherwise, no individual player may feel responsible for making funding decisions and players may argue about who implements, controls and evaluates energy efficiency programs.

- Such programs as the Energy Trust Fund can be cheaper for the public as a whole than paying for power generation.

- Under a UK-type model, the focus on private profits means that less profitable rural areas, which constitute a large segment of the population in some developing countries, are likely to be ignored.

- The UK experience demonstrates that sectoral reforms are very likely to interact with other government policies (in this case EU environmental policy and the UK policies to protect its nuclear industry). The outcome of these interactions may not be predictable. Many developing countries also have protected energy sectors that could potentially undermine or distort power sector reform attempts.

CHAPTER 6
POWER SECTOR REFORMS IN ARGENTINA

With a population of 35 million and a GDP of $279 billion, Argentina is Latin America's second-most important market after Brazil.[1] Its 1995 per capita GDP of $8,100 makes Argentina an upper-middle-income developing country. Argentina is rich in natural resources and has a highly literate population; furthermore, it is a member of Mercosur, the free trade agreement with Brazil, Paraguay, and Uruguay begun in 1995. After struggling with mismanagement and hyperinflation in the 1980s, the newly elected president Menem implemented a comprehensive package of economic reforms in 1989 including the liberalization and privatization of state-run infrastructure services such as the power sector.

6.1 POWER SECTOR CHARACTERISTICS AND REFORMS

From its nationalization in the late 1950s until reforms began in the early 1990s, the Argentinean power sector was wholly state-owned. It consisted of:

- three large, vertically integrated utilities (SEGBA, AyE, and HIDRONOR)
- two transnational hydropower generation companies
- a nuclear entity (CONEA)
- about two dozen provincial distribution utilities
- about 700 electric cooperatives (mostly in isolated areas).

Before the reform, Argentina's power sector was characterized by political interference in tariff setting (particularly, delayed tariff increases to control inflation and distorted tariffs), lax maintenance practices resulting in low generation availability (below 50% for thermal plants), and very high distribution losses combined with theft.[2] These losses reached 30% in much of the capital city of Buenos Aires.

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[1] *CIA World Factbook 1996/97.*

[2] Estache, A. and M. Rodriguez-Pardina, "Regulatory Lessons from Argentina's Power Concessions." *Public Policy for the Private Sector*, The World Bank Group, September 1996.

Furthermore, there were long delays in several prestigious hydropower projects, resulting in huge cost overruns and a ballooning external debt for the country.[3] Large amounts of funds from the federal budget had to be injected into the power sector in the 1980s, which further compounded the country's then-prevalent fiscal crisis. During 1988, the situation culminated in an energy crisis as a serious drought coincided with numerous power system operation and maintenance problems.[4]

Fifty-six percent of Argentina's 1991 installed capacity of 17,500 MW (including 1,800 MW from autoproducers) was thermal (mostly coal and fuel oil), 38% hydropower, and the remainder nuclear. Total gross production was 54 TWh in 1991, with 55% generated by thermal power plants, 30% by hydropower, and 15% by nuclear power.[5] Energy demand by sector was 43% from industry, 32% residential, 10% commercial and 15% other. More than 40% of power demand was and remains concentrated in the greater Buenos Aires region. The peak demand of Argentina's interconnected system (excluding autoproducers and remote electric systems) was 10,400 MW in 1994. This is significantly smaller than the installed capacity because the nation's hydroelectric power plants have a capacity factor of only 30% due to water flow restrictions and plant design.

Restructuring and Privatization

Electricity sector restructuring and privatization were part of a broad plan by the Menem government to privatize public commercial undertakings. These policies were founded on the performance of public enterprises in the 1980s and on a new conception of the state's role in industry sector. The key objectives of the reform efforts were:

- attraction of private investments to ensure a reliable power supply in the long term
- fair and reasonable rates and protection for end-users
- enhanced economic efficiency of the power sector
- a limitation of the government's role in the economy.

Argentina's reforms followed the UK and Chilean models, with the separation of generation, transmission and distribution, and the creation of a wholesale electric spot market (Mercado Electrico Mayorista - MEM). The process began in 1991 and 1992 with the split-up of the generation, dispatch, transmission, distribution and regulatory functions, and the introduction of a wholesale electric power market (Exhibit 6-1). The three main state-owned utilities were split

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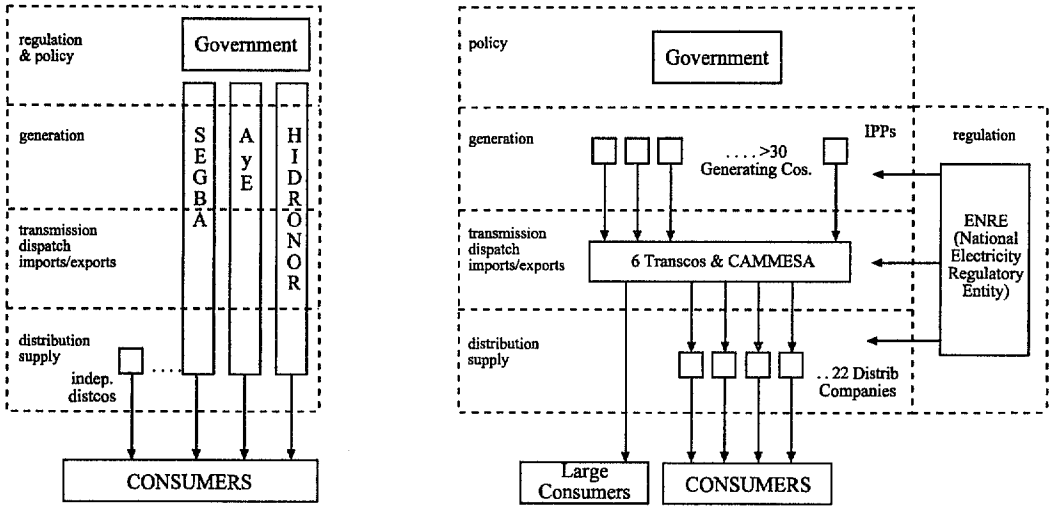
[3] Examples are the 2,900 MW YACRETA plant that has been under construction for almost 30 years and the 4,500 MW Corpus Christi project that has been in planning and development for more than 20 years.

[4] Rudnik, Hugh, "Pioneering Electricity Reform in South America." *IEEE Spectrum*, August 1996.

[5] Heidarian, J. and G. Wu, *Power Sector Statistics for Developing Countries, 1987-1991*, The World Bank, Industry and Energy Department, December 1994.

Exhibit 6-1
Structure of the Argentinean Power Sector Before and after Reform



Power Sector Ownership: Public

Power Sector Ownership: Public, Private, Employees

accordingly. Assets were transferred to separate companies that had been partially privatized by open competitive tenders in which foreign and domestic investors competed on equal footings.[6]

- In the generation segment, 15 of Argentina's 18 major thermal plants and 5 of its 9 large hydroelectric plants have now been privatized. The purchasers include 15 North American utilities, 4 European and 4 Chilean utilities. Plans to privatize the country's three nuclear power plants are pending.[7]

- In the transmission sector, Transener, the main transmission company, and 4 of the 5 regional transmission companies have been privatized.

- In the distribution sector, there are 22 regional distribution companies, most of which are under provincial government jurisdiction and not yet privatized. In addition, the three distribution companies of SEGBA (Edesur, Edenor, and Edesap) have been partly

[6] Lewis, Piers and Dean White, *Separating Electricity Distribution: International Experience*. Report prepared for USAID by Hagler Bailly Consulting, November 15, 1995.

[7] "Country of the Week: Argentina," published on the Website of the Utility Data Institute, 2/20/97, www.udidata.inter.net.

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privatized. These represent a special case, however, as all three serve the Buenos Aires area and together account for about half of Argentina's electricity supply.

Although competition with unrestricted entry and exit has been introduced to the generation segment, transmission and distribution remain regulated monopolies. Some innovative regulatory rules have been introduced to these two sectors to ensure the existence of competitive elements. Transmission and distribution companies operate under long-term concession contracts. The concessionaires have the right to operate the assets and collect the revenues while maintaining specified service, operational and maintenance standards.

The formula for transmission tariffs is set by ENRE (an independent regulatory agency).[8] It also sets distribution tariffs for the three former SEGBA companies, while provincial distribution utility tariffs are set by provincial regulators. ENRE's distribution tariff formula is based on economic costs plus a rate of return that is comparable to other business activities of similar risk and to comparable distribution companies. The tariff formulas include a system of indexation and are fixed for the first five years. Furthermore, there are limitations on the concessionaires, such as a ban on transmission companies buying or selling energy (they can only transport it). Within certain parameters, distribution companies must provide service to everyone requesting it at the set tariff. The regulator applies a penalty system when distributors do not comply with a set of service quality standards. Finally, the concessions are put out to bid by the regulator every 10 years (15 years for the initial period).

Transmission and distribution companies are required to provide open access to third parties after publishing relevant rates. Electric utilities are free to sign supply deals with distribution companies and large end-users (those with peak demand greater then 100 kW) within certain rules. These contracts must be made public. Distribution companies, power producers, private power companies, and industrials may not own transmission facilities. Since January 1997 the regulatory system has allowed power brokers, but there have been no significant activities so far.[9]

Distribution companies are required to supply electricity to the entire population of urban areas. Electricity service coverage reaches about 95% of Argentina's population and roughly 70% in rural areas. In 1996 the Energy Secretariat, together with several provinces, started a rural electrification program that incorporates renewable energy sources and competitive bidding for concessions (Exhibit 6-2).

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[8] In addition to setting tariffs for the six transmission companies, ENRE awards licenses, protects consumers, and oversees CAMMESA, which is responsible for managing the power pool.

[9] Moscote, R., S. Maia, and J.L. Vietti, *The Power Sector in LAC: Current Status and Evolving Issues*, The World Bank, Latin America and The Caribbean Technical Department, Regional Studies Program, Report No. 35, June 1995.

6.2 ENVIRONMENTAL POLICY AND LEGISLATION

Environmental Laws

Due to the low population density in most parts of the country and a plentiful supply of natural resources, there has long been a lack of awareness of environmental problems in Argentina. Also, the majority of environmental problems have been increasing slowly over a long period of time. Consequently, there is no comprehensive federal environmental legislation. Instead, each province and municipality has its own regulations.

Air pollution problems have been primarily limited to large cities such as Cordoba and Buenos Aires (in part because of the permanent wind circulation in most of Argentina). There is a general lack of industrial and vehicle emission control systems. Buenos Aires and some other cities and provinces have started to introduce environmental regulations in the last few years concerning water pollution, waste generation, air pollution monitoring and industrial zoning.

Before the liberalization of the power sector, there were almost no legal requirements for its environmental performance. With the exception of the *Environmental Management Manual for Hydropower Projects*, which was published and became mandatory in 1987,[10] there were no mechanisms for measuring and controlling emissions.

Exhibit 6-2
Argentina's Rural Concessions Program

To promote the extension of services into rural areas, the Argentinean Government has initiated the Electricity Supply Program for the Rural Dispersed Population in cooperation with participating provincial regulatory authorities. Under this program, priority is given to photovoltaic panels, small windmills, hydraulic micro-turbines, and diesel-driven generators. The total estimated investment of US $314 million will be shared, with 45% paid by users, 25% from provincial subsidies, and 30% from national subsidies.

Concessions are being competitively granted to one or more private enterprises in each province on the basis of the lowest subsidy required per supplied user, as well as technical and financial qualifications. The concession will run for 45 years, divided into periods of 15 years at which points the regulatory authority will call for a new bidding process with the prevailing concessionaire having priority. Rates are negotiated between the concessionaire and regulatory authority for five-year periods. The concession will be exclusive for users up to 90 kWh/month.

It is too early to determine the effectiveness of this approach. As of late 1996, three provinces had at least begun the process of awarding concessions, with the remainder expected to do so by 2000. Two bids have been awarded. In each, there were 4-5 bidders, with a wide range in the bid values offered for combined rural and urban concessions. Concessionaires, who are established utilities elsewhere, are beginning with community applications to gain experience in their markets. The next stage will tender separate offers for the urban and rural markets, although the same bidder may bid for both.[1]

[1] Fabris, A., Sevant M. et al. "Argentina Dispersed Rural Population Electricity Supply Program." Secretaria de Energia de Argentina, Presented at Business Meeting about Infrastructure and Energy, Washington, DC, October 22, 1996. Also, personal communication with Aldo Fabris, Secretaria de Energia, May, 1997.

[10] Resolution 718/87 of the ex Sub-Secretariat of Energy.

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However, since 1991, environmental issues have been integrated in the laws and decrees that govern the energy sector's deregulation as well as the privatization process. The law governing power sector privatization explicitly addresses the sector's air and water emissions.

Emission standards for particulates, SO_2 and NO_x from thermal power generation were established in 1993 and strengthened in 1995. The standards are fairly stringent and exceed World Bank standards (Exhibit 6-3). Furthermore, ENRE has conducted two air quality studies near operating thermal power plants. Based on the experience it gained in these studies, ENRE issued a *Practical Guide for Atmospheric Impact Evaluation* in early 1997 that must be followed for power plant expansion or new plants. Also, ENRE, the Generators Association, and the Argentinean Chamber of Environmental Companies have created a joint permanent commission on environmental issues.[11]

Exhibit 6-3
Argentine and World Bank Emission Standards

	Emission Standards for Gas Turbines using Liquid Fuels (mg/Nm3)	Emission Standards for Gas Turbines using Natural Gas (mg/Nm3)	World Bank Emission Standards (mg/m3)
Particulates	20	6	50
NOx	200	200	240

Institutional Structure

The Energy Secretariat is responsible for setting environmental standards for the power sector. It also issues authorizations to utilities for membership in the wholesale electric market that include a requirement to comply with environmental regulations. Official authority for environmental regulation is divided between the power sector regulator, ENRE, and other agencies such as the Watershed Basin Committee and provincial and municipal authorities.

Standards are implemented and enforced by ENRE, which is charged with overseeing the "protection of safety, environment, and public safety [issues] in the construction and operation of generation, transport and distribution systems of electricity," including the right to inspections and investigations.[12] As part of the bidding process for power plants and concessions, bid

[11] "Environmental Implications of the Privatization of the Electric Sector in Argentina," internal memo from Estudio Q, Buenos Aires to Hagler Bailly Services, Washington, April 1997.

[12] Argentinean Law 24065.

documents contain an annex on environmental protection that includes minimum environmental requirements and an implementation schedule.

Despite these efforts, Argentina's environmental management remains inadequate. It appears as if ENRE is primarily trying to establish a consensus with wholesale power market participants before developing or implementing control measures, although the state has an important role in directing environmental regulation.

Enforcement Issues

The Secretariat of the Environment has been criticized for its loose enforcement of existing regulations. Enforcement is reported to be stricter at the provincial level. Buenos Aires, for example, has established its own "environmental police."[13] This split in authority between the Secretariat of Environment, ENRE, and provincial authorities significantly complicates environmental enforcement. Penalties for power plant operators are ineffective and the only apparent penalty for non-compliance with environmental legislation is to disallow future authorizations.

Environmental Impact Assessments

Companies that invest in Argentinean utilities under World Bank support must prepare environmental impact statements and comply with the Bank's environmental standards. Since 1994 ENRE has also required all participants in the wholesale spot market to set up an environmental management plan. These plans must include provisions on how the generators and utilities intend to handle solid, liquid, and gaseous residues and effluents. Utilities must also develop emergency operation plans and plans for emissions monitoring. To comply with the plans, utilities must present quarterly reports on their progress in implementing the environmental management plan as well as weekly plans informing ENRE about emergencies or violations of emissions limits. However, ENRE has not specified sanctions in the case of non-compliance. Since mid-1995, ENRE has hired private consultants to evaluate the environmental behavior of utilities operating thermal power plants and their compliance with environmental management plans. In 1996 it passed a resolution requiring environmental impact evaluations for every power plant expansion.

6.3 ENVIRONMENTAL EFFECTS OF REFORMS

Generation Mix

Since the 1980s, the substitution of natural gas for fuel oil has been a policy goal in Argentina. However, this goal did not begin to be realized until the early 1990s when the demand for natural gas increased in the deregulated power sector and the deregulation of the natural gas sector

[13] EIU Business Latin America, *Environmental Regulations in Latin America*, October 21, 1996.

encouraged the construction of new natural gas transport pipelines. This had the effect of reducing fuel oil use and related air emissions.

Since the privatization of Argentina's generation assets, thermal power plant availability has drastically improved. Presumably, improved operation and maintenance practices have also had a positive effect on thermal generation efficiency and emissions per kWh. Also, utilities have begun to rehabilitate and upgrade existing plants, which will likely lead to some reductions in emissions per kWh. Currently, there are only 2.5 MW of installed windpower in Argentina (mostly by community cooperatives), but substantially more is expected as part of the rural electrification program mentioned above.

Transmission and Distribution Sectors

Initially, the distribution companies focused on reducing power theft, which was as high as 18% in Buenos Aires. Subsequently, they also targeted distribution losses. The losses in the distribution system as well as the reliability of the transmission system have been greatly improved (Exhibit 6-4).

Exhibit 6-4
Selected Power Sector Indicators in Argentina

Year	Availability of Thermal Power Generation (%)	Transmission Forced Outages for Transener (in hours)	Distribution Losses (%)
1992	48.2	1,000	21
1993	59.8	900	20
1994	61.3	650	18
1995	69.9	300	12

Source: Estache and Rodriguez, op. cit.

Electricity Prices and Subsidies

In Argentina, electricity prices generally reflect the cost structures associated with supplying a particular class of end-users and are in a range comparable to prices in the United States. The wholesale spot price has dropped considerably, from 4.2 cents/kWh in late 1992 to 2.2 cents/kWh in 1995. This is primarily due to overcapacity and the high availability of hydropower plants. However, the final prices billed to residential end-users are much higher because distribution companies add up to 20 cents/kWh to the wholesale prices. The average distribution cost to the industrial, commercial and residential customers of privatized distribution companies

is 4 cents/kWh (the actual costs are much higher to serve rural than urban areas).[14] As further nuclear power development is unlikely beyond the Atucha II Project, which is currently under construction, the primary drivers of price in the wholesale markets will be the availability of hydropower plants and the availability and cost of natural gas.

As a key reform, tariffs are now largely based on economic fundamentals. Critics claim that there are still some distortions (e.g., in Buenos Aires the medium-tension industrial tariff is still relatively high compared to the residential tariff). However, before power sector reform, tariffs were based on political decisions that often bore no correlation to the underlying costs of electricity supply.

Subsidies for power have been reduced since the reforms began. Where subsidies have been retained, they have been made transparent. At the federal level, there are two types of explicit subsidies. One, which applies to low-income Edenor, Edesur and Edelap pensioners, is equivalent to 50% of the normal tariff and is paid by Treasury funds. The second applies to electricity-intensive industries (with more than 100 MW end-use and certain other conditions). Also, there is a fixed tax of 0.24 cents/kWh on the wholesale price that is used for transmission investments as well as to compensate for tariff differences in isolated areas. There are additional subsidy programs by provincial governments, including the rural electrification programs mentioned above.

End-Use Energy Efficiency

Large industrial customers reacted to the improved post-reform economic conditions and to the removal of electricity tariff distortions by improving the energy efficiency of their processes. This was largely driven by the internationalization of the economy following the conclusion of the Mercosur agreement. Many multinational companies invested in Argentinean companies and introduced modern equipment as well as operation and maintenance techniques. However, there have been no significant improvements in smaller enterprises and in the residential and agricultural sectors, nor have there been any significant DSM activities by utilities before or after the reforms.

The federal government has begun some energy efficiency activities in recent years, most of them with support from the European Union and the Inter-American Development Bank. These activities include pilot projects in industrial energy efficiency and cogeneration, manufacturing quality improvements in the domestic appliance industry, and energy analysis programs in all sectors. The government's energy efficiency policy focuses mainly on improving the competitiveness of the market for energy services; no major regulatory initiatives are planned.

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[14] Badaraco, Ernesto and Luis Scholand, "Deregulation and Privatization of the Argentine Power Generation Market," paper presented at the Hemispheric Energy Symposium, Miami, October 20-31, 1995.

The IFC is currently planning to support street lighting retrofits with loans, as this activity holds significant economic savings potential.[15]

During the last several years there has been about a 5% annual growth in electricity consumption in Argentina. It is unclear, however, how much can be attributed to the general economic recovery, to increased household appliance penetration, or to reduced electricity prices for some customer groups. The growth rate is several percentage points higher than the growth in GDP (3% from 1994 to 1995), a situation that has existed since the early 1970s.[16]

Technology Commercialization

The power sector's liberalization and the shift to natural gas have led to the rapid introduction of new efficient combined cycle power plant technologies in Argentina. In some cases low-NO_x burners for gas turbines have been installed. Also, power plant operation, maintenance and rehabilitation know-how have been introduced to the sector by outside investors.

6.4 CONCLUSIONS

The environmental effects of power sector reforms must be compared to the power sector's environmental and technical performance before the reforms. In Argentina, such performance has historically been poor, although not extremely so by developing country standards. The positive environmental effects of the reforms can be summarized up as follows:

- improved operation and maintenance of the generation system
- significant reductions in distribution losses and power theft (in privatized utilities)
- reduction of subsidies and introduction of cost-based tariff structures
- encouragement of fuel switching, from coal and fuel oil to natural gas and combined cycle power plants
- introduction of environmental regulations to the power sector.

The negative effects of the reform process are primarily a consequence of lower electricity prices for some customer groups, resulting in reduced incentives for energy efficiency and increased consumption. The magnitude of this last effect is unclear as it currently coincides with a general upswing in the economy resulting in much higher spending on (electricity using) consumer goods. Furthermore, there has been little effort to improve energy efficiency in the small industrial, commercial and residential sectors due to the paucity of interest on the part of these end-users.

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[15] Personal communication with C. Smyser, SMSE Program, Inter-American Development Bank, April 1997.

[16] Moscote R. et al., op. cit.

A critical debate is how to interpret the reduced incentives for the power sector to build large capital-intensive hydropower and nuclear stations in a competitive environment. Often, hydropower plants caused significant damage to local ecosystems, but they do not contribute to greenhouse gas or other air emissions.

Several conclusions can be drawn from the situation in Argentina:

- A clear assignment of authority and funding mechanisms, as well as some central coordination of regulatory authorities, are necessary to the successful implementation and enforcement of environmental legislation.

- In the absence of special energy efficiency programs, there will be little improvement in the efficiency of smaller end-users; there must be clear funding mechanisms (e.g., a distribution levy or general budget funding) if an energy efficiency program is planned.

- The reforms undertaken in Argentina may not necessarily be suitable for developing countries as its sophisticated system of penalties, price indices, bidding of concessions, and specific regulations and incentives might overwhelm the administration of some nations.

- Improved access to natural gas resources, in parallel with power sector reform, has a positive impact on the environmental performance of the power sector; however, only a few developing countries have natural gas supplies as plentiful as those in Argentina.

- The privatization of electricity distribution has created an opportunity to accelerate the deployment of renewable energy systems in rural areas.

CHAPTER 7
POWER SECTOR REFORMS IN INDIA

From independence in 1947 to the early 1990s, India's economic policies stressed self-sufficiency, import-substitution, and state control of basic infrastructure. In 1991 prime minister Rao initiated a sweeping reform program that abolished most industrial license requirements, relaxed foreign exchange controls, reduced trade barriers, encouraged private and foreign investment, and promoted structural reforms in several sectors, including power. Despite a subsequent increase in GDP and foreign investments, India's per capita GNP is still only $320, making it one of the 25 poorest countries in the world.[1]

7.1 POWER SECTOR CHARACTERISTICS AND REFORMS

India's power sector is dominated by numerous agencies, including the Ministry of Power, which oversees and coordinates national power policy, administers and regulates the industry, and approves state requests for investments; and the State Electricity Boards (SEBs), which distribute almost all power in the country. Private utilities contribute only 4% of installed capacity. There is also significant private "captive" power production (about 10 GW) concentrated in such industries as iron, steel, textiles, and sugar.

Capacity in India grew from just over 1 GW in 1947 to more than 81 GW in 1995. Despite this major expansion, India still suffers a supply shortage of about 10% of energy demand and 20% of peak capacity demand, a shortfall of about 13,000 MW in 1997. This severe shortage results in frequent demand curtailment, load shedding, and brown outs. According to newspaper reports, New Delhi recently experienced power cuts for six hours a day. In Kerala State, electricity is sometimes available for only eight hours a day, and farmers in Haryana State have had to let their crops dry because there was not enough electricity to drive the water pumps. Also, voltage and frequency fluctuations cause significant problems for industrial machinery.

Although India's per capita electricity consumption is one of the lowest in the world (318 kWh/a), its demand growth is among the highest (about 8% annually). The SEBs are unable to meet growing demand because of insolvency due to subsidies for rural consumers, poor revenue collection, high T&D losses, poor fuel quality and poor worker training. The power shortages

[1] The World Bank, *World Development Report 1996: From Plan to Market.* Oxford University Press, June 1996.

place serious restrictions on industrial development, have caused a steep increase in (expensive and polluting) self-generation, and are estimated to have led to a 2%-4% loss in GDP.[2]

Electricity rates in India are heavily cross-subsidized and vary widely for end-users within regions and SEBs. Exhibit 7-1 show the tariffs of the pre-reform Orissa SEB, which are still typical for most SEBs. Industries pay more than domestic users and substantially more than agricultural users (the agricultural sector is given preference for available power; subsidies to farmers are reported to constitute about $2.8 billion a year). The power sector's average cost recovery was only 78% in 1993. In addition, some studies estimate that average rates are at least 50% lower than the long-run marginal cost of electricity supply. In 1995-1996 alone, the SEBs accrued commercial losses of $2.2 billion, or about 0.8% of India's GDP.[3]

The government reports average transmission and distribution losses of approximately 20% — in some states they reach almost 50% — however, data quality is generally poor due to the widespread absence of metering and billing data. Power plant reliability is low, with average plant capacity utilization around 60%. Power theft is a also major problem (a study by the National Rural Electricity Cooperative Association estimates that about 13% of all power generated is stolen by end-users). According to recent government statements, only 60% of the power supplied in New Delhi is being billed and only 40% of these billings are collected. Even government offices and municipal bodies are delinquent, and major theft cases are often derailed by the interference of influential local leaders.[4]

Exhibit 7-1
Electricity Tariffs of the Orissa State Electricity Board in 1990

Tariff Category	Paise/kWh
Industrial	**153**
Commercial	**111**
Residential	**58**
Street Lighting	**53**
Agricultural	**34**

Source: Asian Development Bank, *Electric Utilities Data Handbook for the Asian and Pacific Region*, 1993

Peak demand is forecast to increase from 58.5 GW (including captive power demand) in 1994-1995 to 111 GW in 2004 (a 7.4% per year growth rate). India will probably not be able to add this capacity without major contributions from independent power developers. Power Minister Venugopalachari stated recently that India will need about 100 GW of additional capacity in the

[2] Miglani, Sanjeev, "Agriculture Knocked off its Power Pedestal," *Asia Times*, January 22, 1997.

[3] Harvard Business School, *Enron Development Corporation: The Dabhol Power Project in Maharashtra, India; Cases A to C, Rev.* December 16, 1996.

[4] "Power Sector Groping in the Dark Due to Neglect and ad Hocism," *Business Standard (India)*, January 27, 1997.

next 10 years, which will require an investment of $112 billion.[5] The recent shifts towards reducing T&D losses, improving load shape, and addressing collection and power theft problems are economically much more attractive than adding new generation, but they can also be more difficult to implement.

India's extensive rural electrification program has connected 86% of its approximately 550,000 villages to the grid. However, large parts of the population still lack access to electricity, compounded by overextended and overloaded distribution systems for many SEBs. Traditional fuels such as biomass still account for a significant share of energy supplies, especially for cooking. In many cases this causes environmental damage, while emissions from inefficient indoor stoves pose health hazards.[6]

Power Sector Reforms

Compared to the UK and Argentina, India is in an early stage of its power sector reforms. However, because the financing needed to correct the sector's problems is beyond the government's means, the forces driving privatization are strong.

Central Government Reforms. In 1991 the Ministry of Power amended the Indian Electricity Act of 1910 and the Electricity (Supply) Act of 1948, allowing for some competition in generation through the introduction of independent power producers (IPPs). The changes enabled foreign and domestic companies to own and operate generation of any size and source aside from nuclear power, and allowed distribution and direct sales of IPP-generated electricity to customers. Further provisions included a waiver of certain approvals by the national regulatory authority for small projects, a reduction of customs and excise duties on power equipment, a five-year tax holiday for profits made in generation or distribution, and the repatriation of profits in dollar terms with full protection against exchange rate fluctuation for certain projects.

Immediately following the reforms, there was a rush of international investors to build power plants in India. However, most projects have stalled due to the dense bureaucracy, the large number of permits needed, unclear assignment of state vs. federal responsibilities, the poor financial situation of the SEBs. It was not until 1996 that the first of eight, high profile, "fast-track" projects by international investors commenced operation. Nevertheless, IPP development continues and is expected to add significant new capacity in coming years.

The government has been unwilling to provide further sovereign guarantees for IPP projects as they affect India's capability to access world financial markets. Also, the World Bank, Asian

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[5] To satisfy an end-use demand of 1 MW, significantly more generation capacity is needed due to plant unavailability (e.g., for maintenance) and to cover T&D losses and theft.

[6] Reuter News Service, *India: India Needs $100 Bln Investment in Power by 2002*, Reuter Textline, March 12, 1997.

Development Bank (ADB), and others are making future loans contingent upon state-based public sector reforms. As a result, SEBs have become the focus of power sector reform.

In 1996 the government proposed five options for restructuring the SEBs, ranging from corporatization and independent regulation (while retaining their vertically-integrated structure), to a complete unbundling of generation, transmission, and distribution. To establish uniform guidelines, a national action plan for power sector reform was released in January 1997 that endows the states with more authority and includes the:

- creation of independent state electricity regulatory commissions
- commercialization of SEBs to ensure financial viability
- creation of a central electricity regulatory commission (for wholesale generation and transmission of power)
- tariff reform to ensure that no end-user category pays less than 50% of cost of service
- allowance of private ownership and operation of T&D.[7]

The government is working on a comprehensive national energy policy, but is not expected to finish it before 1998. However, there is strong opposition to the reform plans by the Central Electricity Authority (a government agency with regulatory functions which will likely lose some of its powers) and the influential trade unions. Nevertheless, with the power crisis expected to worsen and ministry officials warning that continuing shortages might lead to riots, there is an overwhelming rationale for reform.[8]

State-Level Reforms. The State of Orissa started a radical reform of its power sector in 1993. The adoption of reforms was precondition for a $350 million World Bank loan, which was granted in May 1996. Orissa's main reform objectives were to attract private capital for new investments, make the sector financially self-sustaining, and improve efficiency.

Its reform process includes several phases and is scheduled to continue well into the next century. It includes the horizontal unbundling, corporatization, commercialization, and eventual privatization of the Orissa SEB (OSEB). In April 1996, OSEB was replaced by a grid corporation (GRIDCO) containing T&D operations and two generating companies. The state-wide distribution area is being disaggregated into four smaller areas that are to be privatized via sale or lease, and licensed by an independent regulator. The responsibility for distribution in some "distribution circles" was transferred to a private company in September 1996 under a management contract with a prospect for subsequent privatization of these circles within three years. Eventually, it is planned for GRIDCO to devolve into a transmission company with

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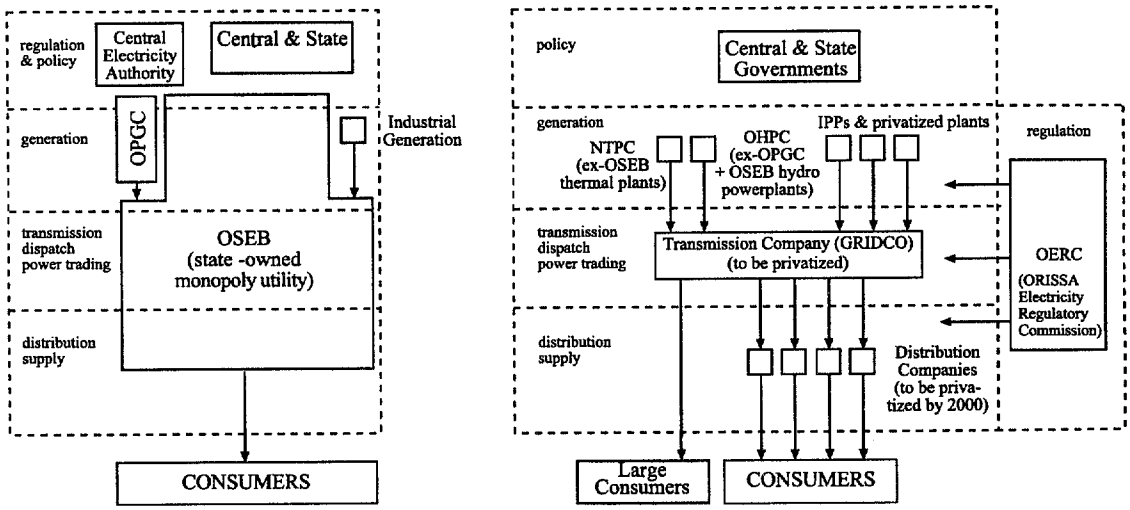
[7] Reuter News Service, *India: Common Minimum National Action Plan for Power*, Reuters Textline, January 30, 1997.

[8] Reuter News Service, *India: Indian Official Warns about Riots over Power Cuts*, Reuter Textline, January 23, 1997.

authority to purchase power for resale, subject to an independent regulator's oversight. Existing generation is expected to be supplemented by IPPs, whose capacity will be acquired through competitive bidding. Exhibit 7-2 depicts the structure of Orissa's power sector before and after reform.[9]

Exhibit 7-2
Pre-Reform and Planned Post-Reform Structure of Orissa's Power Sector



Power Sector Ownership: Public

Power Sector Ownership (planned):

Another key reform was the establishment of the independent Orissa Electricity Regulatory Commission (OERC). The reform bill empowers OERC to govern the power sector for the first time in India, and lays out the rules governing its work (the appointment process for commissioners, terms and conditions of service, funding procedures, separation of authorities and duties between the state government and OERC, and grounds for appealing decisions).

OERC does not regulate the construction and operation of power plants, as the generation sector has been opened up to competition. However, other state regulations such as zoning and environmental protection still apply. In the T&D sectors, OERC will be responsible for ensuring the competitive procurement of power, works, equipment, and materials; granting operating licenses and licenses to sell bulk power; setting rates; resolving disputes and right-of-way issues; and for establishing and ensuring operating standards and service reliability.

[9] World Bank, *Staff Appraisal Report - India - Orissa Power Sector Restructuring Project,* Energy and Infrastructure Operations Division, Country Department II, South Asia Region, April 19, 1997.

The Haryana and Rajasthan governments are now adopting reform legislation and installing independent regulatory commissions. Those of Andhra Pradesh, Uttar Pradesh, Karnataka, Gujarat, Maharashtra, Bihar, Tamil Nadu and Goa have also recently announced plans to reform their power sectors, some with World Bank or ADB assistance. Given the complexities of Indian politics, the success of these reform efforts is still far from being ensured.[10]

Prices, Tariffs and Subsidies

The State of Orissa illustrates the importance of tariffs to the reform process. Before Orissa began its reform process, OSEB's average tariff was below 70 paise/kWh and the average revenue was under 90 paise per kWh (2.5 cents/kWh). Since 1993, tariffs and revenues have been increasing by 15 to 20% annually. The World Bank's projections for GRIDCO (the main successor of OSEB) for FY 1998 assume an average tariff of 244 paise/kWh, average revenue of 251 paise/kWh, and average cost of supply of 244 paise/kWh (6.8 cents/kWh). This indicates the changes in sectoral cross-subsidies as the average revenues are closer to the average tariff due to a reduced spread across various tariff classes.[11]

7.2 ENVIRONMENTAL POLICY AND LEGISLATION

This section describes the principal Indian environmental laws and the institutional structure of environmental agencies, and discusses the relevant regulations for the power sector.

Environmental Laws

Air pollution control in India is governed by three major laws:

- ***Air Pollution Prevention and Control Act*** (1981, amended in 1982 and 1983), which requires all new air polluters to obtain "Consent to Establish" and "Consent to Operate" from the appropriate State Pollution Control Board (SPCB, see below).

- ***Environment Protection Act*** (1986, amended in 1986 and 1994), which requires all industries seeking "consent" under the Air Act to furnish an annual "Environmental Statement" covering quantities of pollutants emitted and the pollution abatement measures taken to the SPCB. It also provides for the establishment of emission standards.[12]

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[10] *Business Standard* (India), "Move to Form New Regulators Upsets CEA," January 6, 1997, and "Engineers Revolt over Move to Curtail CEA Powers," January 30, 1997.

[11] World Bank, *Staff Appraisal Report - India - Orissa Power Sector Restructuring Project,* op. cit.

[12] U.S. Department of Commerce, Environmental Trade Working Group. *India: Environmental Technologies Export Market Plan.* Washington, DC, 1996.

- ***Environmental Impact Assessment of Development Projects Notification*** (1994), which states that any new project or expansion of any existing project requires an evaluation and assessment by the Ministry of Environment and Forests.

The Air Act of 1981 established India's ambient air quality standards, which are different for industrial, residential and rural, and sensitive areas. For thermal power plants, there are only standards for total suspended particulates. They are concentration-based and differ for generators with capacity under 200 MW (150 mg/m^3) and those with capacity exceeding 200 MW (350 mg/m^3). Total suspended particulates, SO_2, and NO_2 levels are monitored in several of India's largest cities; however, carbon monoxide and ozone are monitored only occasionally, and PM_{10} (fine particulate matter) is not monitored at all.[13]

Institutional Structure

India's main environmental management authority is the Ministry of Environment and Forests (MoEF), which was established in 1985. It is responsible for formulating environmental policy and coordinating with other government agencies, pollution monitoring, and the environmental impact assessment (EIA) of development projects. The MoEF concentrates on 18 critical industrial subsectors (including power generation) and 22 "sensitive" geographic areas. The designated geographic areas are concentrated in industrial zones around Bombay, Delhi, and Gujarat, as well as all coal mining and iron and steel manufacturing centers. The MoEF considers air pollution control to be one of its top priorities because of the immediate public health concerns.[14] Its six regional offices are responsible for collecting and furnishing information for EIAs, pollution control and enforcement measures; and maintaining liaison with central and state government agencies and NGOs on environmental issues.

The main enforcement authority is the Central Pollution Control Board (CPCB). Its primary functions are to advise the central government on matters relating to air and water pollution and air and water quality, plan and implement national programs for the prevention or abatement of air and water pollution, set ambient and emission standards, and ensure compliance with environmental regulations.

Most of the states have State Pollution Control Boards, which are India's primary environmental enforcement agencies. SPCBs issue permits ("consents") for industrial discharges to air and water, lay down or modify emission standards for local industries based on the Minimum National Standards and the carrying capacity of sites, monitor compliance with permits, and take

[13] Hagler Bailly Consulting, Inc. *Air Pollution Control Equipment: An International Market Assessment, Final Report.* Prepared for Radian Corporation, Arlington, VA, 1995.

[14] U.S. Agency for International Development, India Mission. *A Strategic Approach to Environmental Protection.* New Delhi, 1994.

legal action against violators.[15] They also impose restrictions on the operation of certain industrial plants and prohibit emissions in excess of standards. However, SPCBs must seek judicial remedies to close down polluting industries and must prove pollution violations.

The SPCBs' effectiveness has been limited by the large number of small industries, lack of technical capacity for monitoring and inspections, slow response from courts on enforcement actions, and lack of public oversight. The Boards are poorly funded and plagued by political interference and corruption.[16] Municipalities and villages are expected to play an increasing role in environmental management at the local level. Under the Constitution Act of 1992, state governments can delegate certain functions to these entities. For instance, municipalities are responsible for water supply for industrial and commercial use. NGOs are also playing an increasingly important role in environmental matters, and the MoEF has requested that they continue their educational efforts and develop priorities for government action.[17]

Enforcement Issues

India's enforcement of environmental standards is unsatisfactory. Several factors contribute to poor enforcement:[18]

- The legal framework does not provide an effective process to prevent, mitigate, or intermediate environmental conflicts in an orderly fashion. Thus, disputes are often resolved through judiciary intervention in constitutional litigation, rather than through a more inclusive and community-oriented system of decision-making. Reliance on litigation not only places a burden on the court system but also excludes some affected groups.

- Institutional factors include: 1) insufficient enforcement authority of the MoEF and the Pollution Control Boards; 2) weak dissemination of laws and regulations; 3) insufficient monitoring of compliance; 4) inadequate capacity for inspection and for taking remedial actions, including follow-up in courts; and 5) lack of required continual legal training.

- A legal strategy has not been developed for using community and non-governmental resources and customary law in environmental enforcement. Given the size and diversity of India and the scale of its environmental problems, even a large expansion of bureaucratic capacity is unlikely to have a significant impact on results on the ground.

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[15] The World Bank. *Technical Annex on a Proposed Credit to India for an Environmental Management Capacity Building Technical Assistance Project.* Washington, DC, 1996.

[16] U.S.-Asia Environmental Partnership, *Country Assessment: India.* Washington, DC, 1997.

[17] MoEF, *National Environmental Action Plan.* New Delhi, 1993.

[18] World Bank, *Technical Annex on a Proposed Credit to India for an Environmental Management Capacity Building Technical Assistance Project.* 1996, op. cit.

- Although corruption and political influence weaken environmental enforcement, compliance has grown over the last few years along with substantial improvements in monitoring. In 1991, less than 10% of polluting industries in the 18 critical industry subsectors had any pollution control. By 1994, more than 65% of these facilities were forced to install control systems or did so voluntarily. Similarly, the cumulative number of court cases decided under the Air Act increased from 136 in 1988 to 318 in 1993. The government won about 60% of the cases.[19] However, large industries have achieved pollution compliance more easily than small ones, which, in aggregate, pollute more.

The most significant enforcement pressure is coming from NGOs, which are increasingly taking the worst polluters to court and are questioning new projects, including power plants. The Indian Supreme Court has been receptive to hearing such cases and has ordered several polluting installations to be shut down.

Environmental Impact Assessment

Until January 1994, only major public sector projects were required to obtain clearance from the MoEF. The EIA Notification makes EIAs obligatory for 29 types of economic activities (including thermal power plants and nuclear power plants), all development projects located in specified ecologically sensitive or fragile areas, and all projects involving investments of Rs. 500 million and above. The regulation also defines a set of required EIA documents. Currently, there are no strict guidelines on who is competent to carry out EIAs, so they are usually conducted by private consulting firms.

EIA documents are initially reviewed by a multi-disciplinary team at the MoEF and then by a specially constituted Environmental Appraisal Committee, which may undertake site visits and interact with stakeholders. In controversial cases, it must hold public hearings (announcements are made in newspapers at least 30 days before hearings). Thereafter, the Committee makes a recommendation for approval or rejection to the MoEF. If an environmental clearance is granted, the Committee stipulates mitigation measures that must be met by the developer. Projects must also submit semi-annual compliance reports to the MoEF.

In April 1997, SPCBs were authorized to conduct public hearings before submitting environmental and site clearance proposals to the MoEF for approval. Public hearings on power plants were made mandatory under amended EIA notification.

Public oversight by such third parties as environmental NGOs over environmental compliance in general and over EIA proceedings in particular is still severely restricted. The Official Secrets Act of 1923 prohibits the disclosure of numerous categories of information to the public. As a result, EIA reports are not disclosed to the public after they have been approved, making the EIA procedure ineffective and prone to corruption.

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[19] The World Bank, *India: Recent Economic Development and Prospects.* Washington, DC, 1995.

7.3 ENVIRONMENTAL IMPLICATIONS OF POWER SECTOR REFORMS

Although power sector reforms in India are still in a very early stage, some general trends can be cited:

Generation Mix
A recent analysis of the introduction of private IPPs since the early 1990s concluded that this activity has had significant positive effects, including:[20]

- stringent environmental reviews for foreign-financed IPPs due to their high visibility
- establishment of more effective management models, construction and operation standards through the examples set by IPPs, resulting in higher generation efficiencies and availability as well as lower emissions
- avoidance of further increases in the use of polluting diesel generators by end-users as currently unmet demand is satisfied
- development of new fuel supply chains with less polluting fuel such as LNG or naphtha (instead of increased use of Indian coal with high ash and sulfur contents)
- support for the development of a private Indian environmental management services industry (e.g., for emission monitoring and waste management)
- great use of renewable power generation.

The negative environmental impacts of IPPs center around increased electricity generation and related emissions. Also, critics feel that privatization reduces government and social control of all aspects of the power sector, including the pollution it emits. They fear that private companies are mostly motivated by a high return on their investment and thus have an incentive to oppose or circumvent environmental regulations, which often mean additional costs. Last, the critics point out that the new coal-fired power plants planned by IPPs follow much lower environmental standards than are customary in OECD countries.

Proponents argue that private power developers (especially international companies) will implement environmental measures that exceed Indian standards and SEB practice due to concerns about their corporate image, increased scrutiny of their proposals, and the possible costs associated with public-sector enforcement. As an example, the MoEF has insisted that IPP developers of coal-fired generation use only washed coal and develop a plan for using all power

[20] Das, Sujit and Thomas Wilbanks, *Private Power Development and Environmental Protection in India*, Revised Draft, prepared for USAID/New Delhi by Oak Ridge National Laboratory, March 1997.

plant ash within 10 years of commencing generation.[21] Another recent analysis concluded that IPPs will make a positive contribution to India's environment.[22] This conclusion is based on the assumptions that power plant performance will be more efficient and that environmental regulations for IPPs will be enforced at least to the same degree as for SEBs.

India's reforms have proceeded largely independently of its extensive policies for renewable energy, which are among the most extensive in the world. The government offers tax concessions, below-market financing, and other schemes to promote renewables development. In some states, SEBs buy power from renewable developers at quoted rates. As of September 1996, about 1 MW peak of solar photovoltaic power plants, comprising over 100,000 solar lanterns, street lights, home lights, and water pumps, had been installed. Plans for a 165 MW solar thermal power plant are moving ahead with support from the Global Environmental Fund and German Government. India is also one of the world's largest markets for wind power. Its hydropower potential ranges from 84 GW to 150 GW, with only 20 GW developed to date. Increasingly, attention is being focused on small hydro projects, where there is a potential of 10 GW, with only 133 MW installed so far.

To enhance the status of renewables, the responsibility for promoting their use was shifted from the SEBs to independent state agencies in the 1980s. Similarly, renewables were given their own cabinet-level ministry and the Indian Renewable Energy Development Agency (IREDA) was founded to implement these policies. In February 1997, the central government announced that it expects 10% or 1,000 MW per year of new capacity additions to come from renewables. While government activities were effective in establishing specialized programs and policies for renewables, they also isolated them from mainstream power sector decision-making under the Ministry of Power. As power sector reforms and privatization move ahead, separate policies and subsidies for renewables will become difficult to maintain.

Transmission Network

Due to chronic under-investment, India generally lacks sufficient transmission capacity to transport excess generation capacity. According to one analysis, the country's total available power could be increased by 11% without increasing generation capacity[23] through greater use of coal-fired capacity. In the short run this will lead to increased emissions. In the long run, better transmission interconnections would reduce line losses, helping avoid the polluting self-generation diesel units and the need to build additional power plants.

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[21] Gupta, Gautam, "Pressure Mounts on Private Power Project Promoters: Environment Ministry Insists on Use of Washed Coal," *Business Standard*, July 29, 1997.

[22] Das and Wilbanks, *Private Power Development and Environmental Protection in India*, op. cit.

[23] Parikh, Jyoti, D. Chattopadhyay, and U. Nandapurkar, "Simulation of National Grid Operation in India." *Utilities Policy*. Vol. 5, No.1, January 1995, pp. 65-74.

The transmission system consists of five regional interconnected power systems operated by regional electricity boards. Since 1993, India's transmission and system operations have been undergoing extensive restructuring with World Bank sponsorship, including the creation of a central government-owned transmission company, POWERGRID, which began full operation in early 1996 and now operates regional load dispatch centers and transmission systems.[24] Also, coordination and control systems are being modernized and bulk power tariffs are being reformed to bring transmission pricing in line with costs. The government recently amended power sector laws to enable private participation in T&D, and has set up a committee to develop guidelines.[25] In Karnataka State, private investors have begun to build a privately-operated transmission line from a new IPP to the grid.

The World Bank's forthcoming Orissa Power Sector Restructuring Project has earmarked $260 million in loans for investments in new and reinforced T&D lines, switchgear, and transformers. These investments are intended to reduce system overload and meet anticipated load growth. A byproduct will be a reduction in transmission losses. However, these losses are generally small compared to distribution losses.[26]

Distribution System

The dismal situation of India's distribution sector (especially metering and collection) will likely make the participation of private players very beneficial for the environment. Assuming that the regulatory framework allows private operators or owners to gain from improvements in system operation, billing and collection, there is a large incentive for a profit-driven private entity to do exactly that. This would result in reduced emissions, through lower losses and theft, and end-user incentives for resource allocation. India's few private distribution utilities are generally considered very efficiently run and are waiting to expand their business activities by managing distribution networks on behalf of SEBs.

For more than a decade, the OSEB consistently reported electricity losses (technical and non-technical) of around 25%. In 1995-1996, a detailed analysis of its T&D system was conducted for the World Bank, revealing that OSEB understated losses (43% in 1996 instead of the reported 25%) and overstated sales, especially to agricultural, domestic, and low-tension industrial customers. Due to the lack of meters or defective/non-functioning meters, many customer groups were charged on a flat-rate basis based on estimated consumption. The Bank estimated that the distribution system's pre-reform technical losses of 23% could be reduced to 11% by the completion of the reform program through investment in new equipment and better management

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[24] PTI News Agency, "Electricity Acts to be Amended," BBC Summary of World Broadcasts, December 23, 1996.

[25] Reuter News Service - India, "India Sets up Panel for Private Power Transmission," Reuter Textline, February 17, 1997.

[26] World Bank, *Staff Appraisal Report - India - Orissa Power Sector Restructuring Project,* op. cit.

(Exhibit 7-3).[27] Under the World Bank project, technical and non-technical T&D losses combined are targeted to be reduced to 24% by the year 2000 and 21% by 2003.

Exhibit 7-3
Estimated Pre-reform Technical Losses and Realistic Post-reform Target Loss Levels for Orissa's Distribution System

Component	Estimated Technical Losses (%)	Target Technical Losses (%)
33 kV lines	6.2%	4.0%
33/11 kV transformers	0.9%	0.75%
11 kV lines	6.7%	2.5%
11/0.4 kV transformers	1.7%	1.0%
LV lines	7.5%	3.0%
Total	**23%**	**11.25%**

Source: World Bank, *Staff Appraisal Report*, April 1996.

Private companies are now installing capacitors to reduce the reactive load and related losses in T&D systems. Asian Electronics (AEL), India's largest capacitor manufacturer, is engaging in performance-based leasing arrangements to install, own and maintain low- and high-tension switch capacitor panels on behalf of the SEBs at utility distribution lines or at utility customer facilities. This reduces transmission losses and creates additional cashflow for the utilities through increased electricity sales to underserved industrial customers. Such schemes will not improve environmental quality in the near term because the efficiency improvements are used to increase electricity sales. In the long term, however, the potential for reducing T&D losses is enormous.

End-Use Energy Efficiency and Load Shape Improvements

With the exception of a few DSM projects sponsored by donor agencies (such as USAID's project at Ahmedabad Electric Company), no significant end-use efficiency programs are being implemented by utilities. Detailed energy efficiency studies have been undertaken for Mahashtra, Andhra Pradesh and Karnataka identifying a large cost-effective potential for DSM measures. However, the paucity of incentives for end-users to reduce peak consumption or more effectively manage their power supply, the general shortage of investment capital, and an overly-bureaucratic planning process have thus far led the SEBs to ignore investments on the demand side.

[27] Note: This compares to 5% to 10% transmission *and* distribution losses in OECD countries.

As part of the Orissa restructuring process, the World Bank included an $80 million DSM component in its loan, of which $50 million will be spent on meters and $30 million on tariff restructuring, load research, individual energy efficiency projects and training. World Bank-sponsored DSM studies identified an initial potential for load reduction of 234 MW in Orisssa's power system in water pumping, public lighting, industrial process improvements, irrigation schemes, and switching to LPG cooking, among others.

7.4 CONCLUSIONS

Despite the very early stage of power sector reforms in India, some general trends in the environmental effects of the reform can be observed:

- reforms lead to plant O&M improvements, transmission system improvements, and large distribution and non-technical loss reductions, and resolved billing/collection problems
- reforms strengthen the role of IPPs in new power generation
- reform will increase the pressure for tariff reform and subsidy removal
- reform will increase overall power production (and associated emissions) to meet unmet demand while reducing the use of polluting and expensive diesel motors for self-generation (however, the overall effect will differ by region)
- reform will shift decision making power from the central to the state level (here, the effect on the environment will depend on individual state governments).

The extent and relevance of these trends will depend very much on the individual state-level reforms in question (especially the degree of tariff reform). Other important factors are the degree to which emission standards and other environmental legislation are enforced, and the availability of public information on plant environmental performance. The worst-case scenario for the environment might be a further delay of reforms, leading to a deepening power crisis and eventually to a backlash against all forms of environmental legislation combined with unrestricted IPP construction by Indian entrepreneurs and a further increase in self-generation by end-users.

Some general conclusions for developing countries can be drawn from this case study:

- The focus on reducing the cost of subsidies in the state budget, meeting power demand and improving power availability and quality is likely to reduce emissions per kWh consumed.

- Unlike in OECD countries, operational improvements in the power system play a key role in assessing the environmental effects of restructuring in developing countries. This is due to the generally poor pre-reform environmental performance of their power sectors (if measured per kWh consumed; in absolute terms the environmental effects are often comparatively small to those of developed countries' power sectors, at least in the area of CO_2 emissions).

- The existing institutional capacity for enforcing environmental standards is not likely to keep pace with the demands of the rapidly growing power sector.

CHAPTER 8
MODELING EXERCISE: EFFECTS OF REFORM SCENARIOS ON AIR EMISSIONS

This chapter uses a simulation model to examine the extent to which various power sector reforms affect the sector's air emissions performance, and how different emissions are affected by a given reform. The analytic approach employed is described first, followed by the model's results for a "prototype" developing country. Next, a series of comparisons shows how the results are sensitive to resource availability. Finally, different reforms are simulated according to conditions approximating those in the state of Andhra Pradesh, India to give a country-specific example of how reforms can cause environmental impacts.

8.1 ANALYTICAL APPROACH

As discussed in Chapter 2, the environmental performance of the power sector is determined by a series of choices made throughout the fuel cycle. Here, the environmental implications of such choices are simulated with regard to total capacity additions, generation type and dispatch. According to the simulation model, new generation resources are chosen on the basis of lowest cost to meet a given level of demand. In the model, reforms affect the level of demand and generation resources that are least cost.

The steps in the analysis are as follows:

1. A series of power sector scenarios is defined: a "base case" (BASE) and five others that combine various reform options described in Chapters 3 and 4. Each scenario defines a set of generation resource emission factors, and an annual load curve that shows the number of hours in a year that various levels of capacity must be supplied. The scenarios used for simulating the effects of reforms on a "prototype country" are defined in Exhibit 8-1. Both the assumed reforms and their associated parameters can be altered to reflect conditions in different countries.

2. A spreadsheet-based tool that simulates resource decisions in a power sector is developed. The tool is based on the concept of a "generation screening curve" that chooses a generation resource to meet a given increment in load (from 0 to 8,760 hours in the year) based upon its levelized cost at the corresponding capacity factor.

Exhibit 8-1
Characteristics of Reform Scenarios for the Prototype Country

In addition to the pre-reform case (BASE), several scenarios were defined that correspond roughly to reform packages being implemented in different developing countries: a commercialization scenario (COMM), a privatization scenario (PRIV), a short-term market scenario (SPOT), a retail competition scenario (RETCO), and an integrated resource planning scenario (IRP). Of course, many other scenarios are possible that combine different reforms in various ways.

BASE - This scenario corresponds to a vertically-integrated, government-owned utility that has managerial problems evidenced by several performance indicators: high forced outage rates for its generators, high variable O&M costs, subsidized power tariffs, poor thermal efficiency, high T&D energy losses, and low system load factor. In addition, in this scenario, government policy subsidizes indigenous coal and lignite. BASE is similar to the situation currently prevailing, for example, in several Indian states and many African countries.

COMM - Here, the (still vertically-integrated) government utility adopts commercial operating principles and practices. The assumed managerial improvements result in the supply-side performance indicators achieving international norms. Tariffs are also reformed to reflect the true costs of service, causing customers to use electricity more efficiently. Examples of utilities that have adopted commercial practices exist in Thailand, Singapore, and Malaysia, and such reforms are being pursued by several countries in Africa.

PRIV - In addition to retaining the performance improvements in COMM, private investment boosts new capacity. Private ownership is assumed to increase the discount rate for evaluating new generation investments over public ownership. It also strengthens incentives for revenue recovery and cost accounting. Private vertically-integrated utilities currently exist in the United States.

SPOT - This scenario is similar to PRIV; however, here a spot market operator buys power from merchant plants. Because of the increased risk in a short-term market, discount rates are higher, and depreciation periods and fuel cost levelization periods are shorter than under the PRIV scenario. Competition among power producers reduces the variable costs of generation and improves performance. Spot or short-term markets currently prevail in Argentina and the United Kingdom.

RETCO — This scenario is also similar to PRIV, but adds competition for end-use customers. Power generators compete for bilateral contracts rather than for a place in a spot market (although another variation could combine retail competition with a spot market). Competition reduces fixed and variable costs, and the retail electricity supplier has incentives to undertake DSM measures that improve system load factor, but not measures that would decrease sales. The UK and Norway have established retail competition, although Norway's power sector is still publicly owned, and the UK has established a short-term market.

IRP — This scenario is again similar to PRIV, but here the utility acquires resources based on least social cost. While not intrinsically part of power sector reforms, we adjusted fuel costs to reflect a $10/ton charge on carbon (about $0.0025/kWh for coal) affecting both new resource acquisition and dispatch. In addition to load management, end-use efficiency measures are assumed to reduce total generation requirements across the load curve by an additional 10%. Several public and private utilities in the United States and elsewhere have adopted IRP principles in response to regulatory pressure. This scenario may be considered an upper bound for environmental performance without imposing limits on stack emissions.

3. A set of input values is selected to characterize the prototype country's power sector. For BASE, published averages for developing countries are used where data are available. When such averages are not available, judgment is used to derive "typical" values for developing countries. To simulate the effects of the reform scenarios, BASE values are adjusted to reflect the relationships discussed in Chapters 3 and 4.

4. Simulations are run using the specified values for BASE and various reform scenarios. Because of the focus on generation choices, the model simulates air emissions and does not evaluate the implications for other environmental indicators. As outputs, the model shows annual emissions of four pollutants: particulates, SO_2, NO_x, and CO_2. Emissions are calculated for each generation resource and then summed.[1]

Appendix B contains a more detailed explanation of the analytical approach used.

8.2 SIMULATION RESULTS FOR PROTOTYPE COUNTRY

Initially, the model is calibrated using "synthetic" data for a prototype country rather than values based on an individual country, as the former is more likely to be representative of conditions elsewhere.

The prototype power sector was specified to have a range of thermal generation options of unlimited capacity plus 500 MW of hydropower available to meet the growth in capacity and generation requirements. The analytical model used does not readily accommodate intermittent renewable options; in terms of emission and cost structure characteristics, hydropower can be considered a proxy for the effects that other renewables have on air emissions.[2]

On the demand side, the BASE load curve was selected for the prototype country representing an increment in peak demand of 1,940 MW, including a 15% capacity reserve margin. The corresponding area under this curve (total annual generation requirements) is 6,190 GWh, giving a relatively low annual load factor of 42%.

The parameter values specified to differentiate each of the scenarios for the prototype country are presented in Exhibit 8-2.

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[1] For each generation resource, emissions of each pollutant are calculated as follows: Emissions (pounds/year) - kWh/year x heat rate (Btu/kWh) x emission coefficient (pounds/Btu).

[2] Hydropower is similar to wind- and solar-based generation in terms of its capital intensity, low operating costs, and resource-limited availability.

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Exhibit 8-2
Power Sector Scenario Parameters for Prototype Country

Parameter	BASE	COMM	PRIV	SPOT	RET	IRP
Discount rate	0.12	0.12	0.15	0.18	0.15	0.15
Adjustment to capital cost depreciation period				0.25 Base	0.5 Base	
Fuel price levelizing period (years)	18	18	18	1	18	18
Reserve margin (%)	15	15	15	10	10	15
System load factor (%)	42	50	50	50	59	59
Load scale factor (T&D and end-use energy savings)	Base	0.8 Base	0.9 Base	0.9 Base	0.9 Base	0.8 Base
Fuel cost assumptions	coal and lignite subsidies	international prices	international prices	international prices	international prices	international prices plus carbon tax
Capital cost adjustment factor	Base	Base	Base	0.9 Base	0.9 Base	Base
Variable cost adjustment factor	Base	0.83 Base	0.83 Base	0.75 Base	0.75 Base	0.83 Base
Operating performance (station energy use, heat rate, and forced outage rate adjustment factor)	Base	0.83 Base	0.83 Base	0.75 Base	0.83 Base	0.83 Base

Each scenario is simulated based on these assumed input values. Results are available in terms of resource choices, annual generation from different resources, total costs, and emissions. Because the approach is intended to give first-order estimates of emissions from different sectoral reforms, the *relative* quantity of the four pollutants is given more attention than their *absolute* numerical values.

Given the generation resources available and the decision rules embodied in the model, the pre-reform BASE scenario selects a mix of 56% fossil and 44% hydro generation (Exhibit 8-3), with lignite contributing most of the fossil generation. Hydro generation is constrained by the total capacity available and the maximum capacity factor. This generation mix results in substantial emissions of the four pollutants (Exhibit 8-4).

Exhibit 8-3
Generation Mix Under BASE (GWh)

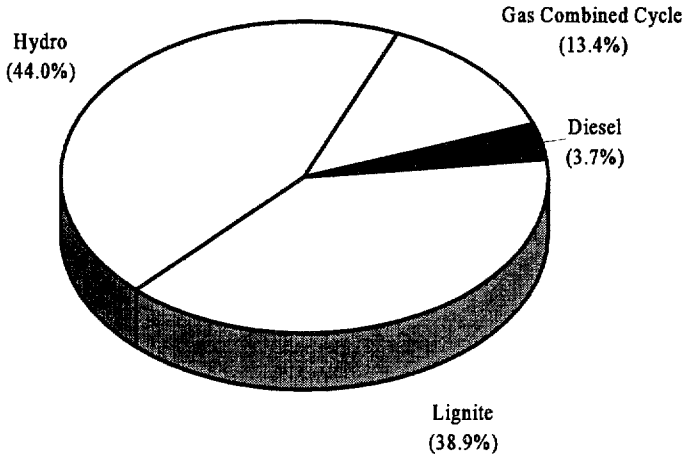

Exhibit 8-4 BASE Emissions Intensity (tons/GWh)	
Particulates	6.5
SO_2	3.6
NO_x	2.2
CO_2	712

The environmental effects of each reform scenario are presented in terms of emissions relative to BASE. To facilitate comparison across emission types and scenarios, Exhibit 8-5 displays percentage differences in annual emissions rather than numerical values. Despite some variation across pollutants, the scenarios display the following environmental ordering from least to most air emissions: IRP, SPOT, COMM, BASE, PRIV, and RET. However, PRIV and COMM show only small deviations from BASE. This ordering demonstrates that reforms can have significant, but not necessarily predictable, effects on emissions.

The reasons for the ordering are more important to understand than the ordering itself, because other plausible input assumptions can be used to produce different orderings. The percentage emission differences that each reform scenario has relative to BASE result largely from the way in which the reforms are simulated to affect the economics of various generation resources and

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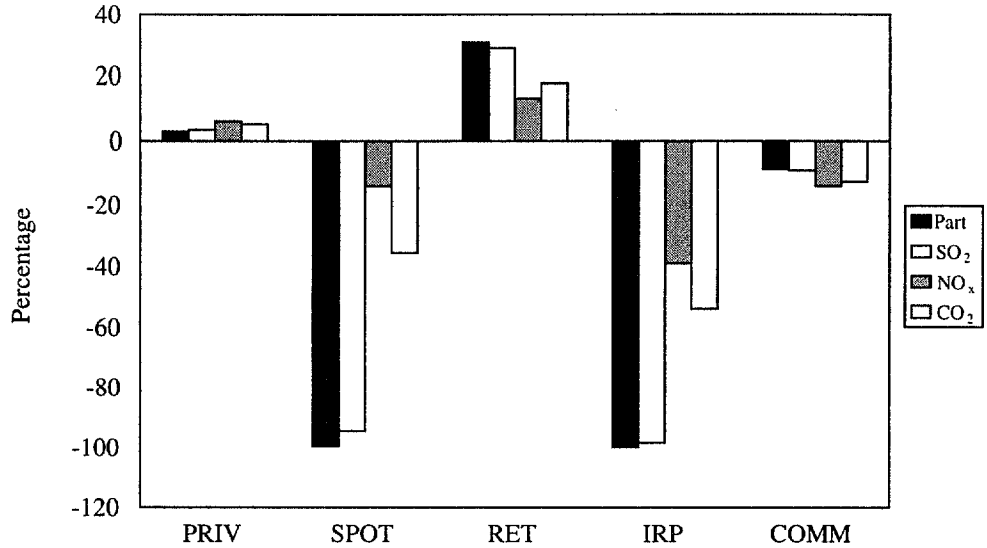
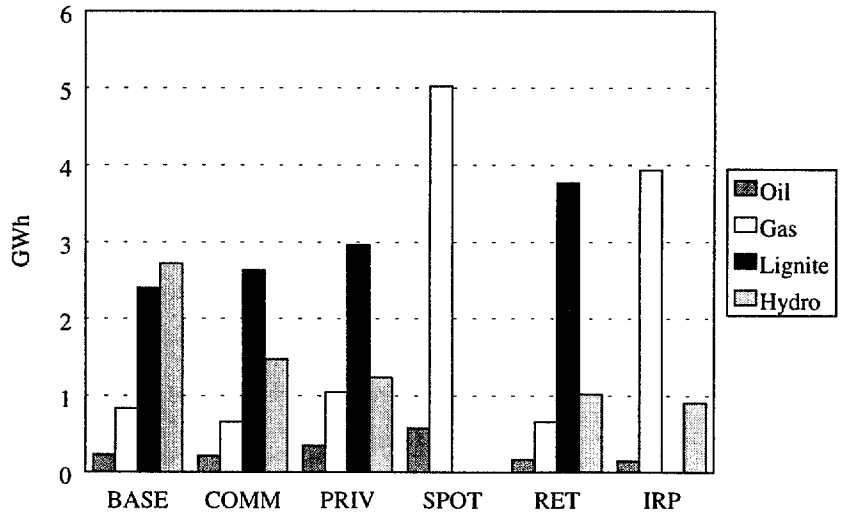
Exhibit 8-5
Reform Scenarios' Emissions Relative to BASE



annual load curves. The interaction between resource preferences and annual load curves, in turn, is expressed in quantities of annual generation by different resources for each scenario (Exhibit 8-6). Interestingly, total emissions are lower in COMM than in BASE, even though annual generation by the resource with the worst emission factors (lignite) is higher in COMM. This occurs because COMM is assumed to burn less fuel per kWh due to heat rate improvements.

Exhibit 8-6
Annual GWh Generation by Scenario and Resource



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The input values account for differences in annual resource use among scenarios relative to BASE. Some of the more important differences from BASE are as follows:

- COMM has lower overall generation requirements, which decrease its hydro generation because hydro is a baseload resource. At the same time, lignite-based generation increases as a result of assumed lowered O&M costs and improved efficiency.

- PRIV evaluates resources using a higher discount rate, causing an overall shift toward fossil generation.

- SPOT evaluates resources using an even higher discount rate, shifting the generation mix to only gas and oil.

- RET uses more baseload (hydro and lignite) generation due to its flatter load curve, moving its generation mix back toward BASE.

- IRP renders lignite too expensive to use at all by imposing a carbon tax, and thus uses mostly gas and hydro.

- IRP and SPOT reduce particulate and SO_2 emissions more than NO_x and CO_2 emissions, which are difficult to eliminate without relying exclusively on renewable resources (here represented by hydropower).

Examining these results further, the effects that reform scenarios have on emissions result, in turn, from how generation choices are affected by input variables. For example:

- Fuel prices affect emissions through generation selection and dispatch. Subsidized lignite in BASE obviously favors lignite generation, while adding carbon values to fuel prices favors hydro, and to a lesser extent, gas and oil.

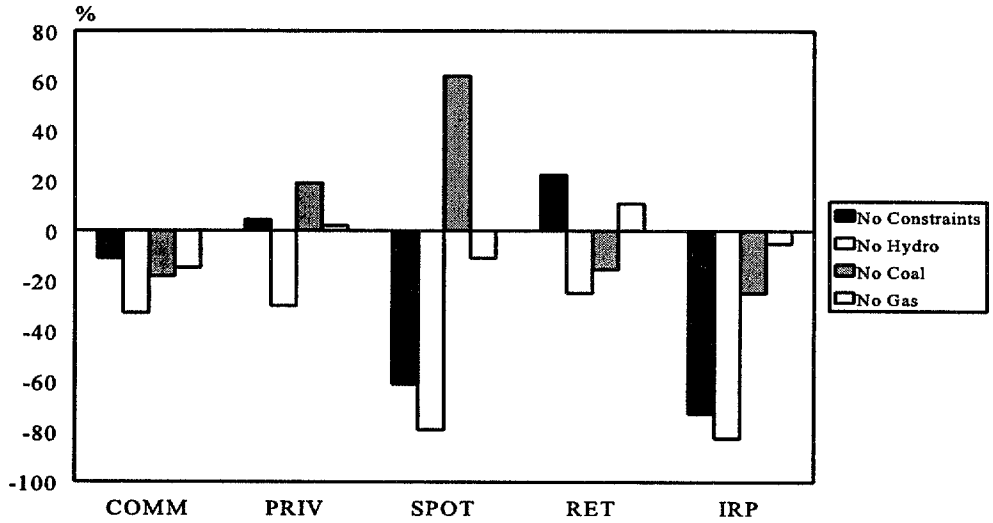
- When the relatively low load factor in BASE is increased (holding total generation requirements constant), the generation mix shifts toward resources that are most economic to operate at high capacity factors (hydro and coal). Scaling down total generation requirements from BASE (while holding load shape constant) tends to have the opposite effect: baseload generation requirements are reduced.

- Shortening the decision time horizon assumed in BASE (by increasing the discount rate, shortening depreciation life, and shortening the period over which fuel prices are levelized) favors operating- and fuel cost-intensive resources at the expense of capital-intensive resources.

8.3 SENSITIVITY RESULTS

In addition to comparing specific reform scenarios for a prototype power sector, a sensitivity analysis was conducted to account for variations in fuel availability. Because the energy resources available to a reformed power sector would affect which generation options are chosen, the model was run four more times, each time leaving gas, oil, coal, or hydro completely out of the resource mix. Other than leaving out oil, such resource constraints affect both absolute emissions and the relative performance ranking of different scenarios (Exhibit 8-7).

Exhibit 8-7
Effects of Resource Constraints on Overall Environmental Performance of Reform Scenario
(Percentage emission differences from BASE averaged over four pollutants)



Leaving hydro out means that a lot of lignite is burned in BASE. This is important because many developing countries have only modest hydro resources that remain to be exploited. In contrast to the unconstrained cases, all reform scenarios without hydro have lower emissions than BASE, because they burn less lignite. Variations among reform scenarios result from how other fossil fuels are burned.

Leaving out coal causes the reform scenarios to have more modest environmental gains over BASE than when these resources are available. Some developing countries don't have significant coal resources. When coal is not part of the generation mix, BASE emissions are lower so the potential for improvement is lower. In the unconstrained case, SPOT shows significantly lower

emissions than BASE. However, in the constrained scenario, SPOT represents a shift in the generation mix from hydro to oil and gas, and thus causes higher air emissions than the BASE case.

Leaving out oil (not shown in the graphic) has little effect on relative emissions because oil generation does not play a strong role in the unconstrained scenarios as they are specified in the model. (In reality, many countries already import oil; even if a country does not have indigenous resources, oil could still play a role in power generation.)

Finally, leaving out gas reduces the beneficial impacts that reform scenarios have on emissions. Many developing countries do not have ready access to natural gas supplies for power generation. Without gas, annual generation in BASE is split between largely between hydro and lignite. The same is true among the various reform scenarios, although the proportions differ.

8.4 RESULTS OF THE COUNTRY-SPECIFIC ANALYSIS

In addition to evaluating how reform scenarios affect emissions in a "typical" developing country, a set of input parameters is formulated based on Andhra Pradesh, India. This state is selected because it faces serious power supply problems similar to other Indian states and is beginning to grapple with alternative power sector reforms. Moreover, a recent report containing relevant data is available for this analysis.[3]

The state utility, Andhra Pradesh State Electricity Board (APSEB) has an installed capacity in excess of 5,628 MW. This is made up of 47% coal, 46% hydro, 5% lignite and 2% gas. This includes about 800 MW (14% of capacity) of APSEB purchases from outside the state. Captive industrial power generation capacity in Andhra Pradesh is about 800 MW. APSEB has led the country in private power development to add to its capacity.

Under the national Electricity Supply Act, SEBs are responsible for setting tariffs to ensure a 3% return on capital. However, the state influences the tariff setting process, especially in election years. APSEB's efforts to increase agricultural tariffs have been ignored, eroding the Board's ability to make prudent investment decisions.

While some private power development has occurred, it is unlikely that a sufficient influx of private investment can be attracted to eliminate the gap between supply and demand without commercialization. In the case of Andhra Pradesh, commercialization is directly linked to private power development.

[3] Hagler Bailly Consulting, Inc., *Integrated Resource Plan for Andhra Pradesh*. Prepared for USAID/New Delhi, May 1996.

In 1997, the state government issued a White Paper calling for several power sector reforms:

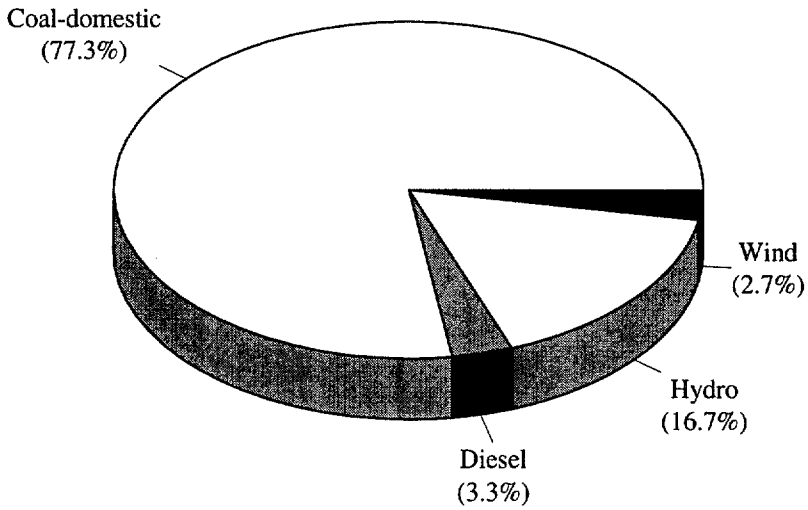
- restructuring the APSEB to form seven independent companies to manage distribution and revenue collection
- establishing an independent tariff regulatory commission
- requiring tariffs for all classes to be at least 50% of the average costs of supplying electricity.

On the basis of current conditions and reforms being considered, several scenarios are developed that reflect possible future expansions of Andhra Pradesh's power sector. As with the earlier analyses, the simulation focuses on a snapshot of added generation, although here a specific year (2015) is the target for the increment in supply.

Base Case — In this scenario (**BASE.AP**), the current institutional arrangements are essentially frozen as of mid-1997. That is, APSEB remains under government control as a vertically-integrated utility; independent private power develops modestly because of APSEB's limited ability to purchase additional power.

Freezing the current institutional arrangements also has consequences for demand. The average tariff declines from Rs. 0.9 in 1994 to Rs. 0.3 in 2015. The annual unconstrained demand growth rate is assumed to be 10%; however, annual supply additions including captive generation

Exhibit 8-8
Generation Mix Under BASE.AP (MWh)



average only 9%. Diesel self-generation partly fills the gap between supply and demand. Line losses increase from 19% to 24%.

As a result of these conditions, the increment in generation is modeled to be largely domestic coal with correspondingly large annual emissions in the target year 2015 (Exhibits 8-8 and 8-9).

Exhibit 8-9
Annual Emissions (pounds) Under BASE.AP

Particulates	1,300,832
SO_2	403,624
NO_x	210,494
CO_2	71,466,476

Four additional scenarios were developed to reflect a range of reforms. These are described qualitatively in Exhibit 8-10 and quantitatively in Appendix B.

REF.AP has essentially the same resource mix as **BASE.AP**; its modestly reduced emissions (in percentage terms) result from lower generation requirements due to the price response to partial tariff reform and supply efficiency improvements.

IPP.AP further reduces emissions through an increase in the discount rate, causing a partial shift from coal to gas. In addition, generation requirements are further reduced as customers respond to tariffs that recover full costs of service.

In **IRP.AP**, the decision horizon and consequently, generation mix, is about the same as that of **IPP.AP**. The reason that

Exhibit 8-10
Possible Power Sector Reform Scenarios for Andhra Pradesh

Reform Package — This scenario (**REF.AP**), roughly corresponds to recently-announced reforms to be implemented: tariffs are reformed to recover 50% of the cost of service. Supply additions keep pace with demand. Of the various resource options, only hydropower remains supply-constrained.

REF.AP — This scenario results in several efficiency improvements. Generation performs more efficiently than under **BASE.AP**. Line losses are reduced to 13%. Based on a price elasticity of -0.2, demand grows at a slower rate than under BASE.AP.

Independent Power Expansion — In this scenario (**IPP.AP**), decisions are made on a private sector basis: demand is further reduced as a result of tariffs that recover the full cost of service; the discount rate increases; and domestic fuel prices subsidies are removed.

Unbundling — In this Orissa-like reform (**UNBUN.AP**), short-term competition for sales to a power pool reduces the time horizon for decision making through an increase in the discount rate, and a reduction in the period over which fuel prices are levelized and capital assets are depreciated. Wholesale competition also drives down capital and O&M costs.

Integrated Resource Planning — This scenario (**IRP.AP**) differs from **IPP.AP** by the shape of its associated load curve. Due to assumed demand-side management activities, generation requirements are 10% less and the system load factor is higher (that is, the load curve is flatter).

IRP with Externality — This environmentally-oriented scenario (**EXT.AP**) is identical to **IRP.AP** except that fossil fuel input prices are adjusted to reflect their carbon content (the adder for coal is $1/mmBtu, diesel $0.60/mmBtu, and gas $0.40/mmBtu).

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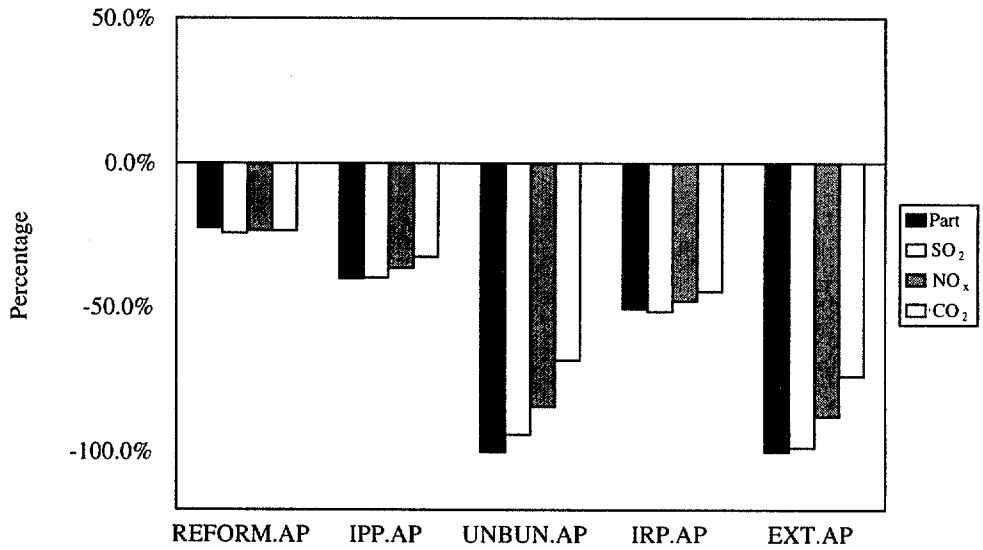
IRP.AP's emissions are lower is because assumed DSM activities reduce generation and peak demand requirements.

UNBUN.AP is modeled to shift the generation mix entirely out of coal and predominantly to gas. This scenario demonstrates that a short-term decision horizon need not hurt environmental performance if gas generation is available. (Wholesale competition in Andhra Pradesh would not likely cause coal-fired generation to be completely replaced by gas-fired generation, given coal's large indigenous resource base. Also, natural gas is less likely to be imported for power generation unless developers are assured of firm sales, which is not assumed in this scenario.)

Finally, **EXT.AP** has about the same generation mix as **UNBUN.AP**, but this mix is a result of increasing the price of coal relative to other fuels rather than by shortening the investment horizon. **EXT.AP** reduces emissions slightly more than **UNBUN.AP**; however, because the demand response to internalizing carbon costs reduces generation requirements by about 5%.

All of the reform scenarios are modeled to reduce emissions over **BASE.AP**. From the least to the greatest emissions reductions (environmentally worst to best), they are **REF.AP, IPP.AP, IRP.AP, UNBUN.AP** and **EXT.AP**. As with the reforms simulated for the prototype country, these differences reflect both generation choices and load curve (Exhibit 8-11).

Exhibit 8-11
Andhra Pradesh Reform Scenarios' Emissions Relative to BASE.AP



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8.5 SUMMARY

In summary, several findings and issues that need to be addressed arise from the above analyses:

- The analyses support the hypothesis that alternative power sector reforms can have substantial, and in some cases, very different effects on air emissions. Relative to a power sector specified to be inefficient in the base case (such as BASE.AP), however, all reforms are likely to improve environmental performance. These results are based on input values within the range of those found in developing countries.

- Reforms affect the selection and dispatch of different generation resources by changing the treatment of their respective fixed and variable costs.

- Not all environmental parameters are affected equally. Reforms appear to cause a greater reduction in particulate and SO_2 emissions than in NO_x and CO_2 emissions because of the emissions characteristics of common resource options (this finding would be even stronger had the relative potential for end-of-stack emission controls been considered). Still, even a modest reduction in CO_2/kWh relative to a base case suggests a role for power sector reform to play in meeting developing countries' climate change mitigation objectives.

- The impact of reforms becomes more difficult to predict when reforms result in new gas generation displaces a combination of coal and hydro additions. For example, even though less hydropower is being added than in the base case, emissions may still decrease because of the decrease in coal-related emissions.

- When some generation types are constrained in terms of fuel availability, maximum capacity, or maximum capacity factor (as is likely in most countries), the relative environmental performance of different reforms changes from when generation choices are unconstrained. For example, in countries that have access to hydro but not coal resources, spot markets that shift new generation from hydro to gas increase emissions over the base case.

The analyses also highlight several issues that need to be addressed in a given country considering power sector reform:

- Given that availability of natural gas increases the leverage that reforms have on environmental performance, can natural gas be made available at an affordable price, especially given the infrastructure requirements for imported gas?

- Given that reforms other than commercialization tend to favor fossil over hydro (and other renewable) generation, how much renewable generation would be developed under the base case?

- Given the important role of generation requirements in total emissions, to what extent can demand be reduced through tariff reform and DSM measures?

CHAPTER 9
CONCLUSIONS

Power sector reform affects the environment in potentially profound but not always obvious ways. It not only matters which reforms are chosen, but also how they are implemented and whether upstream and downstream policies are consistent with the reforms. This chapter draws conclusions about the implications of individual reforms, their effects on key drivers of environmental performance, and why the effects of reforms vary across countries.

9.1 COMPARISON OF INDIVIDUAL REFORMS

In general, as discussed in Chapters 3 and 4, the environmental benefits of commercialization, privatization, and the elimination of fuel and tariff subsidies appear to be stronger than those of vertical unbundling and the introduction of wholesale or retail competition. The exact magnitude of these effects, however, is highly country-specific and dependent on power sector conditions. Given that some reforms have more positive environmental implications than others, a key policy issue is the extent to which it is practical to implement some reforms in a given country. Some OECD and non-OECD countries that began with publicly-owned vertically-integrated monopoly utilities have since moved in very different directions. Their experience, however, does not mean that all reform combinations are practical in a given country. What follows are individual general observations about practical reform considerations, using theoretical evidence, modeling results, and experience from case study countries.

Commercialization reforms have generally positive environmental implications with little downside risk. When a public utility adopts commercial operating principles, improvements in economic efficiency and supply-side energy efficiency are likely to result. Of the various positive effects that electricity sector reform has on environmental performance, several can be realized through commercialization alone without the environmental downsides that other reforms bring. Improved incentives for generation, transmission, and distribution system efficiency are a likely outcome of commercialization. For example, improving the operation and maintenance procedures at a given power plant helps achieve design standards for thermal efficiency and emissions. Commercialization is also often accompanied by tariff reforms. According to the World Bank, however, public utilities' track record for implementing commercial principles has been poor unless privatization also occurs.

Privatizing the power sector's existing assets is more likely to improve their environmental performance if requirements are specified in advance. The incentives to improve supply-side

efficiency and bring tariffs in line with marginal costs become more pronounced when ownership is transferred to the private sector. At the same time, private owners adopt a shorter time horizon than public utilities, which means that investments that deliver quicker payback are preferred. The investment priorities of the new owners will promote environmental improvement to the extent that such requirements are specified in privatization bidding documents or coincide with financial realities.

The environmental implications of allowing privately developed new generating capacity and of introducing wholesale competition depend on the types of generation chosen by developers. Adopting a short-term perspective on generation investments by private developers, especially in response to competition, can improve or degrade environmental performance depending on what type of generation would otherwise be used (for example, hydro or coal). Wholesale competition for power also induces high thermal efficiency as long as capital costs are not prohibitive.

Retail competition appears to be a net negative with respect to environmental performance. Given the adoption of other reforms (commercialization, privatization, wholesale competition), the introduction of retail competition is not likely to improve the power sector's environmental performance incentives and, at worst, creates incentives to maximize kWh sales at least in the short term. The experience of countries which have already introduced retail competition shows that, at best, suppliers of electricity services to retail customers may try to differentiate themselves by offering energy management services to large customers; however, they are unlikely to undertake actions that reduce total kWh sales unless they are given financial incentives to do so through regulation. This finding is particularly important for power sectors that are small or have other characteristics that make the economic benefits of competition relatively modest.

The liberalization of fuel supply sectors affects which fuels are available for power generation. The environmental implications of power sector reform are influenced by concurrent reforms in fuel supply and related sectors. Country policies affect energy choices in upstream sectors (domestic and international fuel trade, fuel extraction and transport, etc.). In a given country, the availability of clean fuels for power production may be as important to sustainability as the reform of power markets. As experience in the UK, India, Ukraine and elsewhere shows, if power sector reforms are undertaken in isolation from other energy market reforms, the potential environmental benefits will not be fully achieved. In particular, the protection of or subsidy to state corporations that produce domestic coal can distort power generation investment choices in ways that reduce environmental benefits.

9.2 IMPLICATIONS FOR KEY ENVIRONMENTAL DRIVERS

Each type of reform can affect the determinants of environmental performance somewhat differently. Exhibit 9-1 shows how different reforms affect generation choice and supply-side efficiency.

Exhibit 9-1
Implications of Power Sector Reforms on Generation Choice and Supply-Side Efficiency
(⇑ = environmentally favorable, ⇓ = unfavorable, ⇔ = depends on implementation)

Reform	Effects on Generation Technology and Supply-Side Efficiency	Effect
Commercialization	Better cost accounting and waste reduction	⇑
	Managerial improvements result in improved operation of generation, transmission, and distribution systems, reducing energy losses	⇑
Privatization	Separation of government and private sector roles allows independent scrutiny of environmental performance	⇑
	New privately developed generating capacity adds to overall capacity	⇓
	Increased capacity displaces inefficient self-generation	⇑
	Higher discount rate favors fuel cost-intensive generation options	⇔
	Tariff reform improves price signals to consider off-grid renewable generation	⇑
	Power purchase terms often favor the development of nonrenewable generation	⇓
	Influx of capital upgrades generation, transmission, and distribution assets	⇑
	Fuel price reform creates incentives for improving supply efficiency	⇑
Unbundling	The ability to capture system benefits from deploying distributed generation depends on structure and tariff regulation	⇔
	Contract terms may or may not give renewables transmission access equal to that of non-renewables	⇔
	The ability to capture supply-side efficiency benefits depends on structure and tariff regulation	⇔
Wholesale Competition	Short-term markets favor low capital cost, dispatchable technologies; not oriented toward renewable generation	⇓
	There is an incentive to choose efficient fossil generation technologies	⇑

Reform	Effects on Generation Technology and Supply-Side Efficiency	Effect
Retail Competition	Competition induces generation choices that minimize short-term costs	⇓
	Retail suppliers might seek a competitive advantage based on the environmental attributes of the generation mix	⇑

Reforms have differential effects on emissions of local pollutants than on carbon dioxide emissions. Of the air emissions examined in Chapter 8, those with local effects are particulates, sulfur dioxide, and nitrogen oxides, while carbon dioxide is of global concern. Shifts in fuel and technology for new generation, as well as load shape, affect local pollutants differently than carbon dioxide because the emission factors for different pollutants vary across generating technologies. For example, if coal-fired generation constitutes the bulk of new capacity under the base (no-reform) case, then most reforms are likely to reduce local pollutants through shifts in fuel type, even if reforms stimulate increased generation overall. Moreover, the environmental regulation of privatized generation could result in emission controls for local pollutants.

Although CO_2 emissions may be reduced as a result of the same reforms, the percentage reduction will not be as large. For example, a shift from coal to gas would virtually eliminate particulate emissions from new generation, while reducing CO_2 emissions by only 55%.

In many countries, the choice of fuel and technology for generation is most potent single effect that reform has on environmental performance. The choice of generation is often the largest single determinant of the power sector's impact on air emissions. Some environmentally-friendly generation options fare better under reform than others. Looking across many countries with reformed power sectors, natural gas generation is most likely the big winner in terms of gaining market share in the near term, assuming availability at relatively low cost.

Most power sector reforms create incentives that favor generating options with lower capital costs per MW and shorter construction time than when generation decisions are made by a vertically-integrated state-owned utility. Because the capital cost intensity of resource options is not necessarily correlated with their air emissions, such incentives could decrease or increase emissions. The capital cost and lead time characteristics of natural gas generation, for example, gives it an advantage over hydro and nuclear generation, as well as coal generation. Within a single fossil fuel type, more efficient and environmentally-friendly advanced generation technologies tend to be more capital-intensive than conventional designs. These technologies may be chosen if the resulting cost of power is competitive.

In choosing among thermal generation types, the effects of reforms depend partly on the local availability and cost of fossil fuels. In the UK, for example, the resource mix available to the privatized sector is causing a shift from coal to gas. In Argentina, the shift is from hydro to gas, while in Asia it is often from hydro to coal. In Ukraine, most fuel and retail electricity

transactions do not take place in cash, if payment is made at all. The resulting lack of working capital limits the choice of fuel for generation. While Ukraine has excess gas and oil generating capacity, it cannot afford to buy these fuels, and instead relies on indigenous and more polluting coal.

Private developers in competitive power markets do respond to environmental policies, but need clear and consistent signals upfront. In competitive power markets, developers seek to minimize project risks, such as the possibility that the host country will tighten environmental restrictions over the course of the project's life. Thus, many developers are adopting internationally-recognized standards for emissions, especially for projects in countries where current regulations are vague or in flux. Different market rules affect which control options are preferred. In the UK, private developers preferred to meet emission requirements by choosing clean fuels rather than adding stack controls to coal generation in order to minimize their capital costs.

Reforms based on short-term decision making could lock-in technologies that may not promote long-term sustainability. Viewing the environmental implications of reform from a static perspective can be misleading about the ultimate effects on the environment. The history of the power industry has long been characterized by the interaction between institutional and technological innovation. Policy reforms themselves can have a strong influence on which technologies are developed, commercialized, and determined to be cost-effective. The dynamic relationship between policy and technology is particularly important when technologies that gain an early foothold create market entry barriers for subsequent but possibly environmentally-superior technologies. For example, if an electricity distributor extends its power grid to remote areas because it does not have authority to choose independent renewable systems, it may never become cost effective to deploy renewables because the power grid is already there.

Different power sector reforms also affect the incentives to invest in bringing environmentally-superior technologies to commercial maturity. The power sectors of some developing countries, such as Brazil, have operated large R&D programs, including programs in sustainable energy options. The fate of Brazil's program as the power sector privatizes and unbundles is not clear. In the United States and the UK, utility R&D budgets have diminished in anticipation of retail competition.

Reforms in developing countries affect end-use demand largely through tariff reform. Because many developing countries still subsidize electricity service, power sector reforms can positively affect the environment by implementing cost-based prices and resulting incentives for customers to improve the efficiency of their electricity use. More effective revenue collection is another outcome of most reforms, the expectation of which enhances the possibility of a customer responding to reformed tariffs with a change in electricity consumption behavior. In addition, price reforms may trigger the emergence of energy service companies that help customers minimize their electricity costs.

Tariff reforms may affect the incentives of individual market actors differently. For example, when retail suppliers directly pass through increased fuel costs are directly to end users in the form of higher tariffs, end users have an increased incentive to reduce their consumption. At the same time, retail suppliers have a decreased incentive. The net effect on electricity use depends on whether the end user or the retail supplier is more likely to implement efficiency measures in response to their respective economic signals.

Because most developing country utilities have not sponsored major demand-side management activities to date, reforms will leave the level of such activities unchanged or cause them to modestly increase. "Pre reform," public utilities that have not had to cover their costs have lacked strong incentives to help consumers overcome the barriers to improving energy efficiency. The effect that reforms can have thus ranges from a missed opportunity to an improvement in such incentives. At best, reforms can create incentives to sponsor DSM activities when certain conditions prevail. For example, if a privatized utility cannot fully recover its costs from certain customer classes, it may lose less money by reducing the demand from such customers. In addition, for as long as power shortages persist after reforms, it may be in the utility's interest to reduce the demand of less profitable customers and sell the saved kilowatt hours to more profitable customers whose use would otherwise be curtailed. Retail competition coupled with some tariff policies may actually create disincentives for the electricity supplier to promote energy efficiency, unless accompanied by complementary regulatory incentives.

Power sector reforms adopted in a given country may increase energy efficiency incentives for some market actors while decreasing them for others. Taking account of their cumulative effects on all the market actors, the net effect of reforms on the adoption of end-use efficiency measures could be positive or negative (Exhibit 9-2). Commercialization and privatization generally strengthen energy efficiency incentives, unbundling's effect depends on how the retail supplier passes through upstream costs. Both wholesale and retail competition tend to weaken efficiency incentives. If the gap is narrowed between the level of energy efficiency justified on the basis of costs and benefits to society as a whole and the level actually achieved. Policy interventions may not be needed to offset the reform's effects. Alternatively, if the gap increases, policy measures may be justified.

The deployment of renewably-based bulk power generation is likely to grow only slowly under most reforms. The prospects for renewables in bulk power markets are mixed, since the advantages of privatization (influx of new capital, breaking the state monopoly on power generation) may be offset by its disadvantages (high discount rates and short time horizons, leading to a preference for the cost structure of thermal generation). The introduction of competition is likely to further damage renewables' prospects in bulk markets without compensating policy interventions. Efficient natural gas-fired generation is more attractive than renewable power generation to developers in competitive wholesale markets for bulk power, for example, in part because of its low capital intensity.

Exhibit 9-2
Implications of Power Sector Reforms on Energy Efficiency Incentives
(⇑ = favorable, ⇓ = unfavorable, ⇔ = depends on implementation)

Market Actor	Retail Electricity Supplier	Customer	Private Energy Service Provider
Commercial-ization	Separate cost accounting and attention to cost recovery ⇑	Tariff reform and improved revenue recovery ⇑	Tariff reform and revenue recovery increases market opportunities ⇑
Privatization	Similar to commercialization, but stronger attention to cost recovery ⇑; higher cost of capital may reduce DSM cost-effectiveness ⇓	Stronger tariff reform and revenue collection ⇑	Tariff reform and revenue recovery increases market opportunities ⇑
Unbundling	Separate profit maximizing decisions ⇔; upstream costs may not be avoidable ⇓; DSM incentives depend on how demand-related costs are passed through ⇔; horizontal unbundling ⇓	Depends on how upstream costs are reflected in bills ⇔	Depends on how upstream costs are reflected in bills ⇔
Competition	Wholesale competition reduces short term costs ⇓; direct access preferable to spot markets ⇔; rate cap regulation creates incentive to maximize kWh sales ⇓; DSM services may be offered to stand out from competitors ⇑	Competition may increase uncertainty over future stream of benefits and force rates down while offering an alternative to reducing bills by reducing use ⇓	Lower and more uncertain future rates decrease market opportunities unless ESCOs offer combined energy supply and demand management ⇓

Other than large-scale hydropower, there are few cases where renewables have made major in-roads into the bulk power markets of developing countries. With some exceptions, this experience is unlikely to change under a continuation of state-owned monopoly utilities. At best, a better managed power sector will be in a position to carefully weigh new options for system expansion. At worst, reforms that strengthen incentives to choose nonrenewable power sources represent not so much a retrenchment as a missed opportunity.

The ability to capture system wide benefits determines the extent to which distributed utility paradigm can be used for overall sectoral expansion. The choice of the centralized or distributed paradigm has environmental implications since several environmentally-superior technologies are more amenable to being deployed in distributed markets (off-grid, demand-side, and grid support installations) than in bulk power markets. Thus, for example, when unbundling

and privatization reforms explicitly address the need to serve rural areas in a least-cost manner, renewables are apt to play a stronger role than under a base case in which rural electrification proceeds by grid extension.

Several reform features can affect the extent to which distributed resources are used:

- With respect to restructuring, the deployment of distributed resources will be determined by the ability of at least one player in an unbundled sector to capture system benefits. In general, prospects are improved when fuel and tariff subsidies are eliminated, when accounting for transmission and distribution costs is separated, and when the distribution provider chooses modes of service extension on the basis of least system cost.

- If reformed power sectors adopt a distributed paradigm, renewables are likely to play a larger role than if reforms promote a central station paradigm. In the near term, renewables will be most successful in competing to serve off-grid customers and other distributed applications where system (generation, transmission, and distribution) costs are high.

- Reforms have the greatest potential to cause the power sector to use distributed resources in countries with large unelectrified populations. In some cases, the privatized distribution company has the exclusive right to serve these people, whereas elsewhere such services may be open to competition.[1]

Regulatory policy will determine the ability of actors within the reformed power sector to capture system benefits from distributed resources. The deployment of these resources depends on at least one actor being able to capture the generation, transmission, and distribution benefits that can result from locating such installations in the grid where system costs are high. If the new rules governing power sectors and rural electricity markets create financial incentives for capturing these benefits, reforms may increase the deployment of distributed resources. For example, the prospects for off-grid applications of renewables are improved when T&D investments are based on a comparison of system-wide benefits and costs.

9.3 WHY ENVIRONMENTAL EFFECTS VARY ACROSS COUNTRIES

The relationship between power sector reforms and the environment varies among developing countries, and between the developing world and industrialized countries. Some of these

[1] Granting exclusivity has several advantages: the distribution company can balance the returns of grid-connected and off-grid customers, absorb market entry costs, achieve economies of scale, and exploit its existing network of local agents. On the other hand, allowing competition may decrease the costs of providing service and ensure that options to grid extension are fully considered.

differences are exemplified in this report's analyses of the United Kingdom, Argentina, and India (Exhibit 9-3). Although the experience is still accumulating, some differences between developing and industrialized countries are emerging with respect to the environmental implications of reform.

Exhibit 9-3
Emissions Implications of Power Sector Reforms in Case Study Countries
(⇑ = favorable, ⇓ = unfavorable, ⇔ = depends on implementation)

Environmental Performance Drivers	United Kingdom	Argentina	India (Assuming Orissa-Type Reforms Implemented)
Generation	Shift from coal to efficient gas generation ⇑ NFFO for nuclear and renewable generation ⇑ Increased cogeneration ⇑	Shift from fuel oil to efficient gas generation ⇑ Reduced emphasis on hydro ⇓ Off-grid distribution concessions target renewables ⇑	Influx of new thermal capacity ⇓ Displaced self-generation ⇑ Separate policies promoting renewables ⇑
Environmental Controls	EU directives require air emission reductions ⇑	Environmental policies integrated into power sector reforms ⇑	Improved plant operation and environmental performance ⇑
Transmission and Distribution	Modest regulatory incentive for T&D efficiency ⇑	Reduction in T&D energy losses ⇑	Targeted reduction in T&D losses ⇑ Better transmission network affects existing plant capacity factors ⇔
End-Use Efficiency	Little incentive for utility DSM ⇓ Retail price decrease ⇓ Energy Saving Trust ⇑	Retail price reduction for some customers; increase for others ⇔ Improved revenue collection ⇑ Lack of incentive for utility DSM ⇓	Tariff reform and improved revenue collection improve customer efficiency incentive ⇑ Planned DSM focus on load management ⇓

The environmental implications of reform are almost always at most a secondary consideration in determining which reforms to adopt and how to implement them. If developing country policy makers undertake reforms are undertaken in an anti-regulatory context of reducing the government's overall role in the sector, then economic efficiency is likely to be favored at the expense of the environment. On the other hand, if the political attitude is that the

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government should retain a role in supplying "public goods", the reforms can be crafted to improve environmental quality.[2] Designing the right incentives at the beginning of the process is easier than going back and fixing things later. For example, initiatives to offset the disincentives to energy efficiency from initial reforms in the UK have had only limited success.

The capacity for developing and enforcing environmental regulations is weak in most developing countries that are reforming their power sectors. As discussed in Appendix A, environmental institutional capacity among developing countries implementing reforms varies considerably. In general, however, their capacity is not as well developed as among OECD countries. In the near term, environmental regulatory institutions in many countries do not have adequate legal authority, monitoring ability, or policy enforcement capability to have sole or primary responsibility for the environmental performance of the power sector. Therefore, it is important to complement environmental regulation with the giving the power sector internal incentives for good environmental performance.

Most reforms will improve the environmental performance of a poorly performing publicly-owned and operated system. The implications of power sector reforms depend on assumptions about the "base case" in which the reforms do not take place. For example, the energy efficiency implications of most reforms are more positive than a base case consisting of an inefficient publicly-owned utility charging highly subsidized rates, but not as good as what might be accomplished by a private and commercial power sector practicing integrated resource planning, especially if carbon values are attached to fuel input prices. The other reforms fall somewhere in between in terms of environmental performance.

The experience of reform-pioneering industrialized countries may be a poor guide to what will happen when developing countries implement similar reforms. Although it is natural to adapt models from other countries, the economic and environmental lessons of industrialized countries may be specific to them. OECD and developing countries have major differences in their sectoral supply and demand characteristics, institutions responsible for crafting and implementing public policy, and political priorities and constraints. Moreover, few countries have accumulated sufficient post-reform experience on which to draw strong conclusions about the environmental effects of reform. Most are in a transition period with market players adjusting to new roles. The short-run environmental effects may be quite different from the long-run implications.

[2] Weil, Stephen, "Instruments for Protecting the Environment in a Restructured Power Sector." 2nd EC/OECD/IEA Workshop on Energy Externalities, Brussels, 1996.

CHAPTER 10
RECOMMENDATIONS

This report's conclusions indicate that a multi-year reform process offers an opportunity to improve the power sector's environmental performance at various stages. Three types of recommendations are made here for realizing this opportunity: policy strategies external to the reform process itself that address its environmental shortcomings, interventions to maximize the environmental benefits of specific reforms, and initiatives for international development assistance and cooperation.

10.1 STRATEGIES FOR IMPROVING THE POWER SECTOR'S ENVIRONMENTAL PERFORMANCE OUTSIDE OF REFORMS

A set of policy initiatives complementary to but outside of the reform process itself can promote environmental improvement. Several of the recommended actions can be used by policy makers to lay the groundwork prior to power sector reforms. Others can be initiated during the reform process.

Strengthen environmental policies and institutions prior to major reforms, especially privatization. As discussed in Appendix A, existing environmental policies and institutions among countries undergoing power sector reform vary widely in their ability to protect the environment. Once a reform decision has been made (for example, establishing rules for wholesale generation markets), the opportunity is at least temporarily foregone. Before new power plants are approved or existing assets sold, the relevant environmental policies should be evaluated, compared with international standards, and considered for strengthening. Even where adequate laws are on the books, regulations, standards, enforcement capability, and legal remedies may need to be upgraded.

Environmental stakeholders should also be able to participate in the reform process. By doing so, stakeholders can ensure that environmental issues are considered at key decision points. For example, the national environmental agency should be given authority to participate in developing reform policies.

Evaluate the environmental implications of reforms being contemplated. A programmatic environmental assessment of reform options is a useful way to improve understanding of their environmental effects. While many developing countries have laws requiring project-specific environmental impact assessments (see Appendix A), they generally do not have regulations

requiring or experience with programmatic impact assessment. Developing the in-country technical expertise to model the reforms' environmental impacts is a key component. Creating the institutional authority, including new enabling legislation, may also be required. The costs for establishing baseline conditions and monitoring impacts should be borne by the power sector.

As part of this assessment, policy makers could establish a benchmark for the environmental performance of the reformed power sector. The environmental outcomes that would be obtained through the adoption of least-social-cost-resource planning and acquisition is one benchmark against which each reform option being considered could be compared. If a given reform fails to meet benchmark environmental outcomes, policy makers would then identify appropriate adjustments to the reform or other mitigating interventions.

If policy makers in energy, environment and finance ministries; elected officials; NGOs; private power developers; ESCOs; and other developing country stakeholders better understand the implications of alternative reforms, a more informed dialogue can take place. While experience from countries that have already adopted similar reforms may be a useful input, candidate reforms need to be analyzed in the context of local conditions.

Implement reforms in upstream sectors that eliminate barriers to the use of clean energy technologies. Policy reforms may be necessary to reduce both subsidies to relatively dirty domestic fuels and barriers to using clean fuels. Examples of the former are to reduce or eliminate subsidies in the extraction, processing, and transport of domestically-produced coal. An example of the latter is to ensure that trade tariffs are not biased against importing clean fuels or technologies.

Determine how power sector reforms affect greenhouse gas emissions. Although CO_2 reductions tend to be smaller than emission reductions of local pollutants, most power sector reforms reduce CO_2 relative to the base case of continued public ownership and control. By implementing those power sector reforms that reduce CO_2 emissions as well as local pollutants, a developing country might be able meet its responsibilities under the Framework Convention on Climate Change without jeopardizing its aspirations for increasing overall generating capacity.

10.2 POLICY OPTIONS FOR INCORPORATING ENVIRONMENTAL PERFORMANCE INTO SPECIFIC REFORMS

The institutional capacity for developing and enforcing environmental regulations is relatively weak in many developing countries. Creating internal incentives for the electricity sector to expand in an environmentally-sustainable manner would reduce dependence on often weak environmental policy. Each of the major reform categories — privatization, wholesale competition, retail competition, and unbundling — offers a potential point of intervention to maximize environmental gains. Of course, the actions recommended here must also be

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considered in light of, and adapted to, local conditions (including institutional feasibility, political acceptability, etc.).

Privatization

Create an independent regulatory body prior to privatization. This recommendation may seem obvious, but many utilities have been privatized before agencies are created to regulate them. Such agencies typically have authority to influence a privatized power sector's decisions over several matters that affect its environmental performance, including terms of sale of power sector assets, retail tariffs, implementation of public mandates (such as rural electrification or demand-side management), and licenses for new plants. The agency may also determine how the unbundled components of the industry interact with each other, such as by developing rules governing wholesale power markets. To the extent possible, the agency should be free of political intervention and pressure from power sector institutions that is not part of transparent regulation.

In addition to indirectly affecting the environmental performance of the sector, the regulatory agency can play a more direct role. A unit within the regulatory body should be created with responsibility for monitoring compliance with environmental performance standards, coordinating with the national environmental agency, and establishing incentives for the power sector to improve its environmental performance (for example, tariffs that incorporate environmental costs).

Include environmental performance as a criterion to select winners when weighing bids for transferring generation and other power sector assets to private ownership. If bids for privatizing assets are solicited through a competitive process, bid selection should include environmental criteria, such as investment in pollution controls. Poland's Ministry of Privatization considers environmental criteria in weighing competing bids for enterprises being privatized. If competing bids are roughly equal under financial criteria, environmental criteria could be used to tip the balance toward the more environmentally-friendly bid. (It is too soon to tell whether such criteria will be used in privatizing the Polish power sector.)

Including such criteria will increase the likelihood that the price paid for assets will reflect the future investment needed to address environmental problems. As a prerequisite, governments should require a third-party environmental audit of power sector assets to determine the investment required to bring the sector to national or international standards. In addition, the privatization entity could establish provisions that examine past environmental performance. A bidder for a privatization would be disqualified if it has a poor environmental record either in the host country or other countries, as evidenced by fines, prosecutions, etc.

Moreover, public access to information on the environmental characteristics of power system assets should be required prior to and after privatization. Without an independent regulatory body, the transition from public to private ownership may take investment and operational decisions out of the public eye. Full public disclosure of environmental information will help ensure that environmental criteria are included in these decisions.

Use the privatization process to leverage improved environmental performance. The incentive that private developers and investors have to minimize risk could be used to improve the environmental performance of privately developed generating capacity. The need for formal contractual arrangements between private companies and governments means that various approvals and clearances (including environmental) will be required for power plants, even if they were not under government ownership. A precondition for private power development is the presence of stable and transparent policies. From the perspective of developers and their financiers, even stringent regulations may be preferable to an uncertain regulatory environment.

The incentive that strategic investors have to minimize project risk represents an advantage for environmental improvement. To use this leverage, new legislation may be needed to allow environmental ministries or other stakeholders to become involved in negotiating terms of asset transfer with investors. The point of leverage at the time of divestiture is how responsibility for environmental problems will be allocated between the buyer and the government selling the asset, and the extent to which such problems will affect the company's price or transferability.

In addition, more stringent environmental regulations imposed on new private generation should be exploited for their positive spill over effects on other power plants. Where a country's generating capacity is to be owned by a combination of public utilities, private utilities, self-generators and IPPs, environmental requirements and incentives for complying with them should be consistent among all owners.

Allocate part of the privatization proceeds to finance sustainable energy investments. While the new private owners may improve the environmental performance of the power sector as a side effect of overall managerial improvements, they are less likely to invest in environmentally-superior technologies with long-term paybacks. Moreover, privatization officials are often reluctant to impose what they consider extraneous conditions on the buyer for fear of jeopardizing the price received from the sale. Developing country governments might, for example, allocate a portion of the proceeds from the sale of public distribution systems to an account that would become available to the new owners or other entities for using renewable resources to electrify rural areas.

Draft model power purchase agreements to avoid biasing them against environmentally-superior technologies. Developing country governments can draft and adopt standard model PPAs that provide incentives for the selection and operation of environmentally superior technologies. Provisions might include: 1) premium rates for projects whose environmental performance exceeds national standards and/or penalties for poor performance, 2) payment terms (such as front-end loading) that do not discriminate against environmentally-superior but capital-intensive generating options with comparable life cycle costs to environmentally-inferior options, and 3) explicit assignment of risks and liabilities associated with future environmental controls between power suppliers and purchasers.

As one example of the last provision, power purchase agreements could specify which party to the agreement will bear the risk of possible climate policy changes, such as a carbon tax, which could increase a project's future operating costs. While the timing and nature of such carbon restrictions are still uncertain, this risk is quite real, especially over the 40-year lifetime of thermal power projects. Because this risk has an associated economic value, the choice of generation may be affected. With such a provision, if carbon restrictions are imposed in the future, both parties would have to agree to renegotiate the agreement.

Enact laws and regulations that clarify and strengthen the responsibilities of private distributors for rural electrification. This will help encourage the development of distributed resource options (including renewable energy). Key decisions in privatizing distribution services include drafting the terms of the utility's sale, criteria for awarding bids, the distribution concession contract, and the subsequent regulation of the concessionaire. The sequence of decisions affects the new owner's technology choices for electrifying rural areas. Because the government retains more leverage over rural electrification prior to privatization of the utility, it should specify at least some fundamental rural electrification requirements in the privatization bidding documents it issues. Then all bidders could assess the associated costs and risks and factor them in to the dollar value of their bids. Beyond minimum requirements, bid evaluation criteria could include business plans for serving off-grid areas in a least-cost manner. Once the contract is awarded, the state could allow a higher return if the concession meets specified performance objectives relating to rural electrification.

Introducing Wholesale Competition

Require wholesale power markets to consider the environmental characteristics of competing generators. Environmental and related operating characteristics could be explicitly included in criteria for evaluating bids for long-term power purchases or short-term markets. The wholesale purchaser could require competing bidders to specify how they would meet a set of performance standards. For example, a thermal plant efficiency standard would require wholesale power sellers to maintain specified heat rates (i.e., 10,000 Btu/kWh or below). If thermal efficiency falls below such a standard, the generation supplier would be required to offset the shortfall with other units that are more efficient than the standard.

Incorporating the environmental characteristics of merchant plants into the operation of spot or short-term markets would require different approaches. One option, which focuses on prices rather than standards, would have the power system operator determine generation dispatch priority based on social marginal costs. Such calculations would include fuel, variable O&M, and external environmental costs (as determined by government regulators). Social cost dispatch would strengthen the incentives of merchant plant developers to choose technologies and fuels with low emission factors.

Retail Competition

Create incentives for retail electricity suppliers to promote demand reduction measures. For countries introducing retail competition, the new market rules should allow competition for energy services rather than kilowatt hours. Under these rules, competing retail service providers could offer electricity supply combined with efficient end-use equipment and energy management services.

Ensure that investments in commercializing environmentally-superior technologies continue to be made in a competitive power sector. Regulators should create mechanisms that assure continued funding to bring environmentally-superior technologies to commercial maturity. One policy being adopted in the United Kingdom and California is a system benefits charge assessed on customers by retail electricity suppliers. Such charges have been proposed in order to recover "stranded benefits" — those investments providing benefits to electric customers that might not otherwise be undertaken by the separate firms in a reformed power sector, especially under retail competition. The objective of this charge is to recover certain costs from all retail electricity customers, regardless of the company from which they purchase generation services (non-bypassable). The charge may be used to fund low-income programs, energy efficiency, renewable energy technology development, or other environmental initiatives. Explicit government bodies may need to be created to carry out these initiatives. Such bodies have been created to act as policy advocates for energy efficiency in New Zealand, England, and Wales.

Unbundling

Ensure equal access to transmission capacity among all types of generation where transmission services become common carriers. Transmission rate structures should not be biased against intermittent renewable capacity. Comparable transmission pricing would help overcome barriers to intermittent or low capacity factor-renewables. If the demand component of transmission charges is based on generation facility's capacity equivalence (e.g., an average level of coincident peak capacity output per month) rather than maximum rated capacity, then intermittent resources would pay their fair share of transmission costs. The energy component of transmission costs should be based on some fraction of total investment in the transmission grid.[1]

Create incentives for distribution and retail components of unbundled power sectors to fully consider distributed resource options for providing electricity services. Relative to a vertically-integrated utility, an unbundled power sector should ideally have an equal or stronger incentive to consider the distributed resource paradigm. To serve this end, regulators should require electricity distributors to analyze distributed resource options in resource planning and acquisition on a least-cost basis. Doing so will first require distribution companies to collect information on area- and time-differentiated marginal costs of service, including generation, transmission, and distribution costs. Because most utilities do not currently have the capability to

[1] Rosen, Richard, Tim Woolf, et al., *Promoting Environmental Quality in a Restructured Electric Industry*. Prepared for the National Association of Regulatory Utility Commissioners. Tellus Institute. Boston, MA, 1995.

collect this information, regulators may need to develop model least-cost analytic procedures and provide training to utilities. This would allow more accurate analysis of the cost-effectiveness of renewables, dispatchable DSM measures, and other distributed resource options.

Consider adopting a renewable energy portfolio standard that is imposed on retail providers of electricity services. One type of initiative for encouraging the acquisition of renewables is to adopt a renewable portfolio standard. Under this approach, retail or wholesale electricity suppliers might be required to purchase a minimum amount of their generation needs through long-term contracts with renewable developers based on competitive bidding (the UK's NFFO approach) or to use renewables for any generating capacity they develop themselves (the Bolivian approach). A version of this being debated in the United States would create a "renewable energy credit" each time a kWh of electricity is generated from a renewable energy source. All retail suppliers would be required to obtain these credits equal to some percentage of the power they sell.

Adopt electricity tariff structures that provide appropriate price signals. The use of regulatory alternatives to price caps will reduce the retail supplier's incentive to maximize electricity sales. Undertaken in Northern Ireland and New South Wales (Australia), revenue capping in regulation would help remove the volume incentive for monopoly suppliers.

Regulators should also craft retail rate formulas that are at least neutral with respect to generation technology. For example, fuel cost pass-throughs should be avoided along with other practices that differentially treat the risks associated with different generating options. However, rate-making could go further. Performance-based ratemaking can be designed to explicitly encourage the acquisition of target levels of renewable resources. Retail suppliers could be encouraged to develop a diverse portfolio of resources based on rate bonuses or penalties. Performance-based regulation can also create incentives for retail service providers to invest in demand-side management by decoupling profits from sales.[2]

Finally, time-of-use and area rates would give appropriate price signals for end users to consider energy- and demand-reducing measures. Time- and location-differentiated rates could be used first in bringing service to unelectrified regions and phased in for grid-connected regions.

10.3 RECOMMENDATIONS FOR DEVELOPMENT ASSISTANCE AND COOPERATION

Bilateral and multilateral development assistance organizations have a variety of tools at their disposal. These include concessional lending, institutional strengthening, technical assistance,

[2] Ibid.

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and analytical studies that would help developing countries implement policy interventions such as those described above. Given limited resources, donors should identify countries whose planned reforms offer the greatest opportunities to shift the power sector in sustainable directions. These agencies can provide assistance to enhance the environmental benefits of the reforms being considered. Some options to consider are as follows:

Make environmental performance improvement an explicit component of technical and financial assistance to the power sector. Rather than assume that environmental performance improvement will be a side benefit of sectoral reform, development assistance organizations should make it an explicit component of technical assistance and loan packages. It is true that the worse the pre-reform environmental performance of a country's power sector, the more likely that any reform will cause some improvement. Nonetheless, growing local and global environmental threats demand that international agencies take a more proactive stance. Fulfilling this recommendation could take several different directions:

- Help countries review their environmental policies in the context of power sector reform.
- Co-sponsor an international workshop on the environmental implications of power sector reforms and on how to design and implement reforms that improve the sector's environmental performance. Use the forum to disseminate information on the results of this study and related projects.
- In training programs and on-site technical assistance for power sector privatization, develop explicit environmental guidelines. In hiring advisors to client country power ministries, incorporate these guidelines in the consultant's terms of reference.

Multilateral development banks, in particular, should become more pro-active in integrating environmental sustainability into loan packages for energy sector reform. They should also help client countries understand the environmental implications of alternative reforms.

Ensure that institutional capacity for environmental protection is in place before providing assistance to the power sector. Donors should provide technical assistance to ensure that a country's institutional capacity for developing, implementing, and enforcing environmental policy is in place prior to reforms. Possible indicators of institutional capacity might be the presence of an environment impact assessment of policy reform options, establishment of environmental performance benchmarks in privatization bidding documents and concession contracts, and market incentives compatible with improved environmental performance (such as elimination of fossil fuel and tariff subsidies or adoption of full social cost power dispatch rules).

Help developing country governments design indigenous solutions to power sector problems that promote environmental sustainability. Due to the lack of indigenous alternatives, developing countries tend to adopt electricity technologies and policy frameworks from

industrialized countries. Successful institutional models for the electric power sector that have been pioneered in one country have been widely observed among developing countries.

Bilateral and multilateral assistance organizations should help developing country governments design indigenous models for power sector structure, operation, and regulation that are environmentally sustainable. Donors should provide technical assistance in developing indigenous structural models and institutional mechanisms for sustainable energy development that are geared to the power sector characteristics of specific client countries. For example, unlike OECD countries where the World Bank more often looks for models, many developing countries have characteristics that might be better suited to a distributed rather than central station model of power sector expansion. The distributed utility model might call for a completely different sectoral structure than reform trends in OECD countries would suggest. In such countries, the structural models being promoted should ensure that distributed resource options can fairly compete to provide electricity services.

Provide leadership to the independent power industry to adopt standards of environmental performance. Multilateral and bilateral assistance agencies should develop a collaborative project with the international power industry and private lending institutions whose goal is to develop a voluntary code of conduct for power sector projects and privatizations. This initiative would generate set of sustainability principles for international power development and a plan for promoting their adoption in the larger power development community.

Help in-country environmental stakeholders become more involved in power sector reform processes. Assistance agencies could develop country-specific strategies to engage key environmental policy makers and other stakeholders in host countries in their reform processes at critical decision points. For example, they could sponsor a facilitated multi-stakeholder dialogue over a long enough period to craft recommendations for incorporating environmental considerations in power sector reforms. Donors could also develop and implement twinning arrangements that pair U.S. federal and state environmental officials who have addressed electricity industry restructuring issues with their developing country counterparts.

Conduct analyses of the implications of power sector reforms on environmental performance. Donors might develop and pilot test a simple analytic tool that would enable in-country decision makers to compare the relative environmental implications of alternative power sector reforms. (A simple example is the model used for evaluating power sector scenarios in Chapter 8 of this report.) Donors might also sponsor studies that estimate the greenhouse gas implications of alternative power sector reforms, particularly in countries with large fossil fuel resources (i.e., China, India, Indonesia, Russia), and develop alternative approaches for guiding the reforms in more climate-friendly directions.

APPENDIX A
POWER SECTOR ENVIRONMENTAL POLICIES IN COUNTRIES UNDERGOING REFORM

Several factors have a bearing on the environmental effects of power sector reform. These include a country's environmental policies, its institutional ability to establish and enforce policies, the existence of air quality regulations, the provision of information on the environmental impacts of individual projects, and the ability of stakeholders to participate in environmental policy development. This appendix reviews the policies of several countries undergoing power sector reform.

A.1 CHILE

Chile's power sector reforms predate its environmental laws by several years. The basis for its environmental policies is the Environmental Framework Law of 1994, which establishes new standards and regulations, time frames for polluter compliance, and requirements for the development of monitoring and abatement systems. The law also requires environmental impact assessments (EIAs) for all environmentally significant development projects.

Decree DL 185 (1991) is Chile's only regulation that specifically addresses air pollution. Issued by the Ministry of Mining, it regulates emissions of sulfur dioxide, particulate matter, and arsenic from smelters. However, the environmental management implications of this law go beyond the mining industry.

Currently, there is no centralized environmental agency in Chile. The National Commission on the Environment (CONAMA) is responsible for coordinating environmental policy via the ministries. Each ministry has standard-setting responsibility for its sector. For example, the Superintendency of Sanitary Services is responsible for both municipal and industrial wastewater management, air pollution is the responsibility of the Ministries of Health and Agriculture, and energy sector regulation is the jurisdiction of the Superintendency of Electricity and Fuels. Enforcement responsibilities are divided between the ministries and the Regional Environmental Commissions (COREMAs) established in each of Chile's 13 political regions. COREMAs also participate in evaluating environmental impact statements.

CONAMA, CEDRM, and the Ministries of Health and Agriculture are developing a system of tradeable permits for SO_2 and particulate emissions using the U.S. program as a model. Companies would buy emission credits as well as the right to bring in new emission sources. The

revenues from selling tradeable permits will go into a fund that will finance environmental equipment purchases.

Decree 185 established a network of air pollution monitoring stations in Chile. It also designated three types of pollution zones on the basis of compliance with the SO_2 ambient standard: "saturated" (exceeding the standard), "latent" (with SO_2 concentrations at 80-100% of the level of the standard), and "unsaturated" (with levels below 80% of the standard).

All of the country's industrial plants have until December 1997 to achieve national emission standards. In the Santiago area, the standards are set at 50% of the national emission standards. New sources are required to meet applicable standards when they begin operations.

A.2 MALAYSIA

Malaysia's relatively comprehensive environmental regulatory framework predates its power sector reforms. The framework is based on the Environmental Quality Act (EQA) of 1974, which contains provisions for air, noise, and water pollution; soil degradation; and oil pollution. Fifteen regulations have been enacted under EQA, including the Clean Air Regulations of 1978. The Environmental Impact Assessment Order of 1987 required EIAs for more than 35 economic activities, including energy. Several amendments adopted in 1995 are designed to strengthen environmental enforcement, including an increase in prison terms and fines for environmental violations, more stringent emission standards, auditing requirements, and the power to close down polluting factories.

Malaysia's Parliament passed important new amendments to EQA in June 1996 which establish substantially higher penalties for emission violations, require polluting firms to engage a third party to conduct environmental audits, and provide for the collection of pollution charge and fine revenues, which will go to a special environmental fund that will finance environmental research, conservation, and pollution prevention.

The Department of Environment (DOE) under the Ministry of Science, Technology and Environment (MOSTE) is responsible for implementing the EQA, including standard setting, ambient monitoring, and, with the states, enforcing pollution regulations. Air pollution is one of DOE's major concerns. Its State Offices and the Enforcement Section of the Control Division are the primary entities responsible for enforcing national effluent standards, issuing licenses and contravention permits, and dealing with appeal cases. MOSTE also supervises the EIA process which is receiving increasing emphasis in Malaysia. Despite an extensive regulatory framework, enforcement remains inadequate due to DOE's lack of sufficient authority, financial resources, manpower, and technical skills.

The Environmental Quality Council formed under EQA is responsible for developing environmental legislation initiatives. It includes members of the federal and state governments, academia, the private sector, and nongovernmental organizations. EQA requires each emission source to obtain a license for its emissions. The Clean Air Regulations established a set of emission standards for criteria as well as hazardous air pollutants for existing and new emission sources. The principal emission standards are summarized in Exhibit A-1.

Exhibit A-1
Malaysian Air Emission Standards for Stationary Sources
(g/m^3 unless otherwise noted)

Pollutant	Existing Sources	New Sources
Sulfur oxides (SO_x)	0.25	0.20
Particulate matter	0.50	0.40
Nitrogen oxides (NO_x)	2.50	2.00
Hydrogen sulfide (H_2S)	5 ppm	5 ppm

Source: The Clean Air Regulation, 1978.

Malaysia's regulatory framework relies heavily on such command-and-control instruments as fines and penalties. Recently, however, it has implemented a number of market-based incentives, including pollution charges, tax reductions, and deposit-refund systems. An intergovernmental committee on economic instruments, established in 1996, is examining ways to apply economic instruments for environmental management on a wider scale.

EIAs were made mandatory in Malaysia under the EIA Order of 1987 and have since become a key part of its environmental regulatory efforts. The Order requires any developer that intends to carry out an activity subject to an EIA to first conduct a study to assess the activity's potential environmental impacts and mitigation measures. The proposed project cannot commence operations until DOE and/or the regional offices have evaluated and approved the EIA. Public participation in the EIA process is guaranteed by the Freedom of Information Act of 1972. The committee reviewing EIA reports includes NGO representatives; the reports are also available to the public.

A.3 PAKISTAN

As one of the first countries to open up to private power development, Pakistan's power sector reforms began well before its institutional capacity in environmental policy was well developed. In fact, until very recently, environmental management was a low-priority issue among Pakistan's policy makers and general population. Despite the fact that an Environment and Urban Affairs Division (now the Ministry of Environment, Urban Affairs, Forestry and Wildlife) was

established in 1973 and the Environmental Protection Ordinance was promulgated in 1983, the government was indifferent to environmental protection until early 1990s. A marked increase in concern for environmental issues resulted in the promulgation of the Pakistan Environmental Protection Ordinance (PEPO) of 1997. Although PEPO established an extensive institutional framework for environmental management, there is no clear division of responsibilities among the government agencies dealing with environmental issues.

The Pakistan Environmental Protection Council (PEPC) was established in 1983 as the supreme environmental policy-making body in the country, but remained largely ineffective for its first ten years. Headed by the Prime Minister, PEPC is responsible for the approval and overall implementation of comprehensive national environmental policies and National Environmental Quality Standards, and for delegating powers to control environmentally damaging activities.

The Ministry of Environment, Urban Affairs, Forestry and Wildlife was established in 1996 to administer and coordinate the nation's environmental activities and to liaise with international agencies and donors. However, its effectiveness is seriously hampered by under-staffing and limited technical and financial resources.

Pakistan's Environmental Protection Agency (federal EPA) was established in 1984 to develop national environmental policy, design and implement environmental standards, increase awareness and disseminate information on environmental issues, and conduct environmental monitoring. It also establishes guidelines and requirements for EIAs. Provincial EPAs are to be established in all four provinces to implement all functions advised and delegated by the federal EPA. Currently, there is great disparity among the provincial EPAs' capabilities and resources.

There are no specific air pollution regulations in Pakistan. National ambient air quality standards do not exist. Standards for stack emissions are set at the provincial level but are not effectively enforced, and are neither capacity-based nor industry-specific. Exhibit A-2 presents emission standards for selected pollutants set by the Punjab EPA. The standards are the same for existing and new pollution sources.

Pakistani law provides for the establishment of an environmental impact assessment system, but it applies only to new projects. PEPO states that every new project proponent must submit an initial environmental examination (IEE) to the federal EPA or, if the impacts are expected to be significant, conduct an EIA and submit a detailed environmental impact statement (EIS). The EIS should include an analysis of the impacts (both manageable and unavoidable) and the proposed mitigation measures.

Exhibit A-2
Air Emission Standards for Stationary Sources in Punjab Province, Pakistan
(g/m3)

Pollutant	Emission Source	Standard
Sulfur oxides (SO_x)	sulfuric acid plants other sources	6.00 0.40
Particulate matter	oil combustion coal combustion	0.30 0.50
Nitrogen oxides (NO_x)	nitric acid plants other sources	3.00 0.40
Carbon monoxide (CO)	any source	0.80
Hydrogen sulfide (H_2S)	any source	0.01

The federal EPA reviews the EIS and can invite public participation in the project's assessment. However, no information may be released relating to trade, business, or manufacturing secrets, processes or techniques, or financial, commercial, scientific or technical matters. After completing its review, the federal EPA may either approve the EIS or recommend to the federal government that the project be modified or rejected on environmental grounds. The EPA is required to communicate its approval or rejection of the IEE or EIS within four months from the date of submission. However, there is no follow-up enforcement of the decision, especially since provincial EPAs lack the power and resources to demand pollution control from industry.

A.4 THE PHILIPPINES

The basis of the regulatory framework for environmental management in the Philippines was formed during the Marcos administration (1972-1986), when the President issued a number of Presidential Decrees (PDs) that created a rather comprehensive policy framework for environmental protection and management. Among the most important of these are:

- The Pollution Control Law (PD 984, 1976)
- The Philippine Environmental Policy (PD 1151, 1977)
- The Philippine Environment Code (PD 1152, 1977)
- Establishing the Environmental Impact Statement System (PD 1586, 1978).

The Aquino administration established the Department of Environment and Natural Resources (DENR) and its Environmental Management Bureau (EMB) and Pollution Adjudication Board (PAB). Local Government Code (RA 7160, 1991) delegated certain environmental management

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responsibilities to Local Government Units. In 1995, the DENR further implemented EIA provisions for large-scale development, a move designed to environmentally complement "Philippines 2000," the government's major development initiative. Its implementation, however, has been slow.

As the country's main environmental management institution, DENR is responsible for the conservation, management, development, and proper use of the Philippines' environmental and natural resources. The EMB advises DENR's Secretary and is responsible for environmental policy formulation. It develops and recommends environmental management and pollution control legislation and policies, and advises the Regional Offices on their implementation. EMB also designs air and water quality standards, emission and effluent standards, and solid and hazardous waste management regulations. The representatives of various agencies, including the Department of Energy, participate in the Environmental Officers Committee coordinated by EMB to ensure that their sectoral development policies and programs are consistent with the national environmental policy. The PAB is a quasi-judicial body charged with adjudicating cases brought by DENR's Regional Offices.

The air quality regulatory structure in the Philippines includes ambient air quality standards, point source (industrial) emission standards, vehicle emission standards, and standards on fuel content. Ambient and industrial emission standards were updated in 1993. The ambient air quality standards exist for 6 criteria air pollutants (the same as in the United States) and 11 hazardous air pollutants. They are as or more stringent than those in the United States. The Philippines also has emission standards for SO_x, NO_x, particulates, CO, and H_2S from stationary sources. In principle, these standards apply to all stationary sources, although they are primarily targeted at power generation. Exhibit A-3 presents the Philippine emission standards for existing and new sources.

The Philippines' SO_2 standards are generally more stringent than those in most OECD countries, with the exception of Japan. *These standards are not sensitive to the size of a source or fuel type.* The standards for particulate matter are less stringent than those in developed countries, although for some areas they are actually stricter than may be required by ambient conditions. Its NO_x emission standards are rather lax and therefore are the cheapest emissions to control.

The country's emission standards are not sufficiently linked to ambient standards: they are purely concentration-based and do not account for pollutant loading. As a result, co-located polluting industries may comply with emission standards individually (and thus not be regarded as violators), but the airshed in question may exceed air quality standards. On the other hand, polluters are allowed to exceed specific emission standards if they can demonstrate that ambient standards have not been exceeded, which does not provide polluters with an incentive to reduce their emissions. Such inconsistency among air quality regulations makes their effective enforcement difficult.

Exhibit A-3
Philippine Air Emission Standards for Stationary Sources
(g/Ncm unless otherwise noted)

Pollutant	Existing Sources	New Sources
Sulfur oxides (SO_x)	1.50	0.70
Particulate matter	0.30	0.15 (urban/industrial areas) 0.20
Nitrogen dioxide (NO_2)	1.50	1.00 (coal-fired plants) 0.50 (oil-fired plants)
Hydrogen sulfide (H_2S)	200 g/MWh within 5 years for geothermal plants	150 g/MWh
Carbon monoxide (CO)	0.05	0.50

Source: The World Bank.

The principal environmental permits required under Philippine law include the Environmental Compliance Certificate (ECC), the Authority to Construct (ATC), and the Permit to Operate (PTO). DENR has the authority to issue these permits; however, the Laguna Lake Development Authority is authorized to issue ATCs and PTOs within its jurisdiction. EMB issues ECCs for projects of "national significance" and those that require an EIA.

The EIS system in the Philippines applies to industrial and energy pollution sources that are part of Environmentally Critical Projects (ECPs) or are located in Environmentally Critical Areas (ECAs). As a planning tool, the EIS system affects project design so as to limit and mitigate a project's environmental impacts. Its regulatory function is realized through the issuance of ECCs, which certify that the requirements of the EIS system have been met.

The EIA documents, including the EIS itself, are reviewed by an EMB Technical Review Committee. Once a project's technical acceptability is established, the public must express its approval of the project either through endorsement by community leaders or (in cases of major projects) public hearings held by EMB and the relevant DENR Regional Office. To resolve issues of technical or public acceptability, the project proponent may be asked to implement mitigation measures that would automatically become conditions of issuing an ECC.

The drawbacks of the EIS system are that 1) certain environmentally significant industries are not included on the list of ECPs, 2) many projects begin construction before an ECC is issued, 3) the roles and responsibilities for monitoring ECC compliance are unclear, 4) annual renewals of

permits hinder their enforcement, and 5) the penalty for construction or operation without an ECC or violation of the ECC conditions is too small to be a deterrent to violations.

The power industry supported DENR's promulgation of DAO 11 in 1995. This "programmatic compliance" regulation gives industries incentives to locate in regional industrial centers around the country. The economic incentives include single programmatic EISs for co-located industries and a promise of government support in analyzing the environmental carrying capacity of an area in order to properly allocate pollutant loadings. The power sector, with multiple facilities, saw this program as being potentially advantageous owing to its regulatory and cost efficiencies.

A.5 POLAND

As Poland has pursued macroeconomic (including power sector) reforms, it has strengthened its environmental policy. Four principal environmental laws in Poland are relevant to air pollution:

- Statute on the Protection and Shaping of the Environment (1980), which provides a legal basis for the protection of environmental media and includes guidelines for air pollution.
- Law on Environmental Protection (1989), which establishes the current institutional structure for environmental management.
- Ordinance on the Protection of Air against Pollution (1990), which sets new air quality standards for 44 major pollutants. The new standards are more stringent than those of the EU and WHO guidelines.
- National Environmental Policy (1991), which sets specific short- (1995), medium- (2000), and long-term (2020) strategic goals for environmental protection. Particular attention was paid to coal-based emissions: SO_2, NO_x, and particulates. By the year 2000, SO_2 emissions are to be reduced by 30%, NO_x emissions by 10%, and particulate emissions by 50% (all compared to the 1980 levels). Largely due to the economic downturn and the reduction of industrial output, Poland was able to meet these quantitative goals by 1992, but it remains to be seen whether the target levels will be sustained once the economy recovers.

The Ministry of Environment is responsible for environmental policy development and implementation, and the coordination of environmental investments. The national policy goals are largely implemented at the provincial (*voivodship*) level. Each of the 49 *voivodships* has a Department for Environmental Protection (DEP). The DEP is in charge of issuing permits, setting maximum allowable emissions, and collecting pollution fees and fines.

The main environmental enforcement agency is the State Environmental Inspectorate. This agency can impose fines, and has the right to stop polluting activities and disallow new economic activities that do not comply with environmental requirements and standards. In addition, the Inspectorate collects data and issues reports on the state of the environment in the country. Each *voivodship* has an Inspectorate for Environmental Protection, which handles the duties of the State Inspectorate at the local level.

The system of national (NFEP), regional, and local Funds for Environmental Protection and Water Management is designed to support environmental projects through grants and loans. Their funds contribute about 50% of the resources for all environmental projects in the country.

Poland has very stringent ambient air quality standards. The 1990 Ordinance on Air Pollution introduced emission standards for the power industry (more than 90% of Poland's SO_2 emissions and 60% of its No_x emissions derive from the combustion of coal). Exhibit A-4 presents selected Polish emission standards for existing and new power sector sources. Under the Ordinance, *voivodship* authorities can set stricter requirements on local plants to meet air quality standards.

Exhibit A-4
Polish Air Emission Standards for the Power Sector
(g/GJ fuel input)

Fuel	Existing Sources			New Sources		
	SO_x	NO_x	TSP	SO_x	NO_x	TSP
Coal						
fixed grate	720	35	1370	650	35	1370
pulverized	870	170	130	200	170	130
Fuel oil						
< 50 MW	1250	120		1250	90	
> 50 MW	170	160		170	120	
Natural Gas						
< 50 MW		35			35	
> 50 MW		85			85	

Poland has been rather successful in introducing economic instruments into its environmental management practices. Polluting enterprises pay fees which increase proportionally to the volume of emissions. If emissions exceed the permitted level, firms are fined at a rate 10 times higher than the fee charge rate. Still, fee rates are not high enough to make them a strong incentive to reduce pollution, so they serve mainly as a revenue source. Fees are often waived in return for investment in pollution control by the enterprise.

Poland's legal basis for EIAs is a government decree of 1985, which requires that EIAs be completed for all new projects and involves 1) a determination of existing environmental conditions at the proposed site, 2) a determination of project's possible impacts during both construction and regular operation, 3) the planning of mitigation measures, and 4) a determination of the costs and benefits resulting from the investment.

A.6 UKRAINE

As with Poland, macroeconomic reforms and environmental policy development have been proceeding concurrently in Ukraine. Among the environmental laws adopted since Ukraine declared independence in 1991, the most relevant to the power sector are:

- the Law on Protection of the Environment (1991, amended in 1995), which declares the country's principles of environmental management and establishes an institutional framework for environmental policy development and implementation
- the Law on Air Protection (1992)
- the Law on Ecological Expertise (EIA) (1995).

The Ministry for Environmental Protection and Nuclear Safety (MEP) is Ukraine's leading environmental regulatory and enforcement agency. It has regional offices in all the *oblasts* (administrative units) and two cities, Kiev and Sevastopol, which have a separate legal status. Some of the regional offices have branches at the rural district or municipal level. The Ministry is under-funded and understaffed at all levels in relation to its responsibilities. It manages the following elements of the environmental regulatory policy:

- design (together with the Ministry of Health) and enforcement of a system of ambient standards for air, water, and soil
- permitting for all major stationary pollution sources, which includes setting loading limits for each regulated pollutant that are designed to achieve ambient standards
- monitoring of emissions and discharges and enforcement of permits, including on-site inspections, imposition of fines, suits for damage compensation, and suspension or closure of violators
- collection of pollution charges
- environmental impact assessment.

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Ukraine's other institutional actors include the Parliamentary Committee on Ecology (develops environmental legislation with MEP), the Ministry of Health (MOH, which plays a lead role in designing ambient standards, and monitors air and water quality in residential areas), the Hydrometeorological Service (the lead air and water quality monitoring agency), and municipal councils, whose environmental representatives participate in enforcement at the local level.

Ambient standards form the basis of the air regulatory program in Ukraine. However, the number (and in some cases) excessive stringency of these standards (which exceed international norms) make them impractical. The resulting complexity of the system undermines enforcement efforts. Ambient standards are used to set individual emission (loading) limits for each enterprise through a modeling exercise that calculates an individual source's contribution to ambient pollution. An enterprise manager contracts an industry or research institute to undertake the analysis to establish loading limits, employing standard air dispersion models. The models rely on data provided by the plants themselves. The proposed limits must then be formally approved by MEP and often by MOH. The loading limits become part of the permit and serve as a basis for calculating the pollution charges to be paid by the enterprise.

In conjunction with the permitting process, MEP has developed a pollution charge system for air emissions, wastewater effluents, and waste disposal, as mandated by a 1992 government resolution. The pollution charges are intended to be the primary incentive mechanism for polluters to reduce their emissions and a revenue-raising mechanism for financing environmental projects. Each pollutant is assigned a rate per ton, based on an estimate of the damage it causes (the estimates were prepared by an institute of MOH). The charge system covers approximately 300 air pollutants (this excessively large number creates a serious impediment to enforcement). With minor exceptions, the charge system makes little distinction based on the ownership or size of the emission sources.

The charge system is not operating efficiently because of the difficult economic conditions of most polluting enterprises and administrative inefficiencies. Local authorities can decide whether unprofitable enterprises can be partially or totally exempted from charges. For example, thermal power plants have been allowed to pay only 10% of the applicable pollution charges until January 1996. In some cases, charges are not being paid at all or are being paid in arrears without adjustment for inflation.

With respect to EIAs, MEP reviews investment projects over a certain monetary value or those classified as particularly dangerous. Other projects listed in the EIA legislation but of lesser value are subject to reviews by *oblast* or local MEP authorities. Each developer is required to file a report on the environmental impacts of its prospective investment (an EIS), taking into consideration the opinion of local authorities. On receipt of the EIS, MEP forms a board of EIA experts to review it. Public participation is envisioned in controversial cases, but the law does not provide for public hearings or other procedures involving the public. The project is either accepted (with amendments, if needed) or rejected by a senior MEP official within 30 days of the

EIS submission. This process contains a contradiction between the assessment and decision-making authority of MEP, which makes the objectivity of the decision questionable.

A.7 SUMMARY

Among the countries surveyed, there is wide variation in the strength of environmental laws and the capacity of the institutions. Environmental policy for the power sector is established and enforced by different agencies than those developing power sector policy reforms. Moreover, environmental policy has not been re-evaluated in the context of these reforms. To the extent that an EIA process exists, it covers individual projects but not government policies. (In contrast, the U.S. Federal Energy Regulatory Commission was required to conduct an environmental assessment of its proposed transmission access rule.) Environmental agencies have no explicit authority to participate in policy-setting in the power sector. While uncertainty over future environmental control costs is but one risk factor facing developers, the fact that environmental laws and policies are still evolving increases investors' risk in new power projects.

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APPENDIX B
POWER SECTOR SIMULATION MODELING EXERCISE

This appendix describes the simulation of the resource acquisition and dispatch decisions made under various sector reform models whose results are presented in Chapter 8. This analytical framework is intended to show the relative importance of individual power sector reforms for air emissions in developing countries. To facilitate the comparison, the results are presented as a snapshot of the resources needed to meet a given increment in load in a hypothetical year. This "comparative static" framework retains the primary purpose of comparing the environmental implications of alternative reforms.

B.1 MODEL DESCRIPTION

As discussed in previous chapters, power sector reforms potentially affect several variables that determine the type, capacity, and operation of generating options: discount rate, cost of fuel, heat rate, energy losses, motivation for demand-side management, environmental costs, etc. A simple and transparent method was used to examine these linkages: developing a spreadsheet model that simulates resource acquisition and dispatch decisions. The steps in the model are:

1. The model develops "generation screening curves" that show the levelized cost of each available type of generation as a function of how much it is used over the year (the full range of possible capacity factors). In the screening curves used here, a future year (8,760 hours) is divided into 20 intervals of 438 hours each. For each interval, the model picks the lowest-cost resource based on its fixed and variable costs (see, for example, Exhibit B-1). With low capital and high operating costs, diesel generation is initially the low-cost resource at low capacity factors, but this form of generation increases quickly in cost. In contrast, hydropower, with high capital and low operating costs, is the low-cost resource at high capacity factors until it reaches its maximum capacity factor.

2. The model maps this resource screening output onto an annual load duration curve to determine how much capacity of each of the least-cost resources is obtained (see, for example, Exhibit B-2). Annual generation is determined by an algorithm that dispatches the selected resources according to their variable costs to meet the next increment in load.

Exhibit B-1
BASE.AP Resource Screening Curve

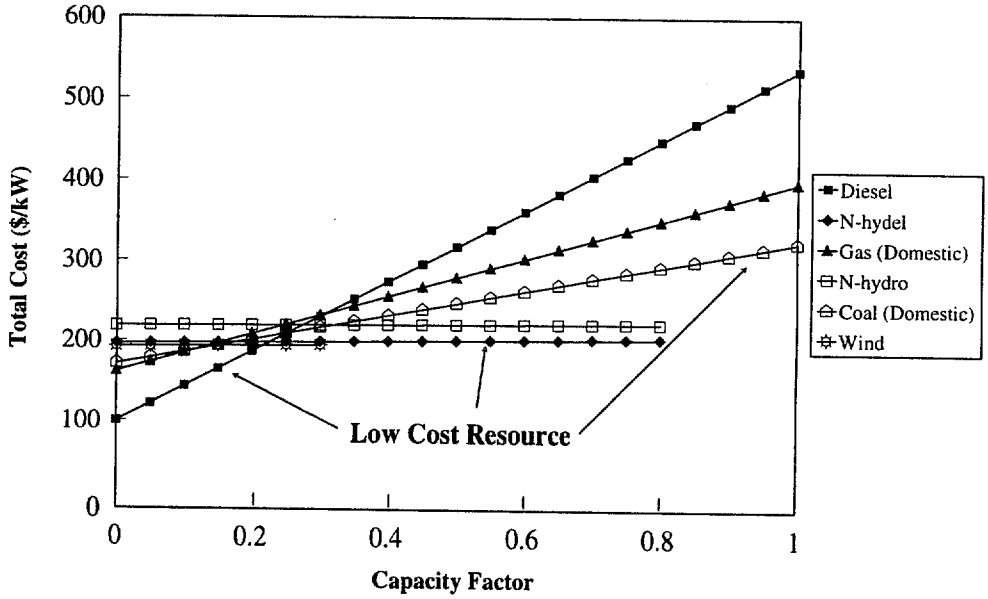
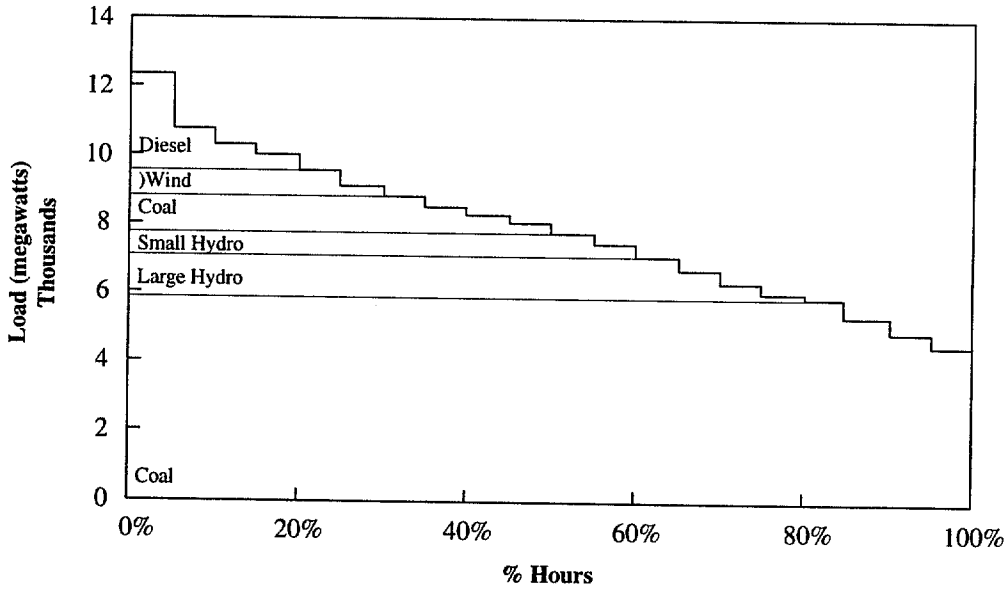


Exhibit B-2
BASE.AP Load Duration Curve and Generation Dispatch



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3. The model then calculates total annual emissions of particulates, SO_2, NO_x, and CO_2 based on the annual fuel simulated to be used by a chosen resource (mmBtu/year), the emission coefficient (lbs/mmBtu) associated with each fuel (Exhibit B-3), and the resource's heat rate (Btu/kWh).

Exhibit B-3
Air Emission Factors for Simulated Generation Types
(lbs/mmBtu)

Generation Type	Particulates	SO_2	NO_x	CO_2
Diesel fired-gas turbine	0.014	0.609	0.14	158.79
Residual oil-fired diesel engine	0.0113	2.093	0.37	165.66
Coal-steam turbine	4.808	0.921	0.83	217.02
Residual oil-fired steam turbine	0.023	2.169	0.45	165.66
Natural gas combined cycle turbine	0.002	0.001	0.52	109.77
Hydroelectric plant	0.000	0.000	0.000	000.00
Lignite-steam turbine	2.799	1.458	0.77	254.96

The approach used here has several limitations:

- The assumptions used to generate input values from which to compare pre-reform with different post-reform scenarios are necessarily subjective.

- The approach simplifies what is in reality a dynamic and more complicated decision process for resource acquisition and dispatch. Relatedly, it simplifies the determinants of environmental performance of selected resources. For example, in reality the heat rate of thermal units improves when they are cycled less. And the aggregate air emissions reduction from end-use energy efficiency improvements occurring with T&D energy loss reductions is somewhat less than the sum of the emissions reductions from the two measures considered separately.

- The model does not incorporate all the linkages between sectoral reforms and environmental implications, some of which are simply not amenable to this type of analysis. Thus, not all environmental differences among reform options will show up in modeling results (such as the displacement of captive generation). On the other hand, the model does account for changes in operating efficiency associated with commercialization and other reforms by adjusting input values for heat rate, forced outages, and other factors.

- Supply options and load curves can only be adjusted rather crudely. For example, the model adds generation resources in continuous amounts, whereas in reality they have discrete capacity sizes.

These options and their characteristics are presented in Exhibit B-4.

Exhibit B-4
Resource Option Assumptions under BASE

		Diesel-Gas Turbine	Residual Oil-Diesel Engine	Coal-Steam Turbine	Residual Oil-Steam Turbine	Natural Gas-Combined Cycle Turbine	Coal Steam Turbine w/ Scrubber	Hydro electric Plant	Lignite-Steam Turbine
Gross rated capacity	MW	78.54	22.5	195	195	116.5	300	50	150
Station use	% net capacity	0.01	0.015	0.07	0.05	0.03	0.07	0	0.07
Forced outage rate	% net capacity	0.12	0.08	0.1	0.11	0.07	0.04	0.02	0.06
Planned maintenance	days	20	22	40	35	25	40	2	40
Maximum capacity limit	MW	no limit	no limit	no limit	no limit	no limit	no limit	500	no limit
Maximum capacity factor	%	100	100	100	100	100	100	95	100
Capital cost	$/kW	600	1800	1200	1230	970	1400	2500	1200
Depreciation life	years	20	25	35	35	25	30	40	30
Variable O&M	$/MWh	3	5	6	5	4	7.8	0	6
Fixed annual O&M	$/kW	1.5	2	3	2.3	2	3	1	3
Heat rate	Btu/kWh	14000	8500	9000	8900	8300	9500	3420	9900

B.2 ANDHRA PRADESH

Exhibit B-5 shows the characteristics of the resource options assumed to be available under the BASE.AP scenario.

Exhibit B-5
Resource Option Assumptions under BASE.AP

		Imported Coal	Wind	Diesel	Domestic Coal	Large Hydro	Small Hydro	Domestic Gas Combustion Turbine	Imported Gas Combined Cycle
Gross rated unit capacity	MW	500	5	25	500	221	50	216	200
Station use	% net capacity	9.5	0.2	5	9.5	1	1	3	2
Forced outage rate	% net capacity	8	2	11	10	2	2	7	7
Planned maintenance	days	30	10	22	40	2	2	25	25
Maximum capacity limit	MW	no limit	500	7000	10000	1000	500	1000	no limit
Maximum capacity factor	%	100	30	100	100	80	80	100	100
Capital cost	$/kW	1200	2000	800	1200	2000	2400	1162	1214
Depreciation life	years	35	40	25	35	40	40	25	25
Variable O&M	$/MWh	5	1	5	7	1	0.5	4	4
Fixed annual O&M	$/kW	2	1.3	2	3	1.2	1.3	21.7	11.8
Heat rate	Btu/ kWh	8500	3420	13700	10000	3420	3420	9300	7940

The five scenarios modeled to analyze possible reforms in Andhra Pradesh are shown in Exhibit B-6.

Exhibit B-6
Scenario Characteristics for Andhra Pradesh

Parameter	BASE.AP	REF.AP	IPP.AP	UNBUN.AP	IRP.AP	EXT.AP
Discount rate (%)	8	8	14	18	14	14
Depreciation period adjustment	none	none	none	0.5 BASE	none	none
Fuel price leveling period (years)	18	18	18	9	18	18
Annual system load factor(%)	59.7	69.6	69.6	69.6	79.6	79.6
Load scale factor	1	0.8 BASE	0.7 BASE	0.7 BASE	0.6 BASE	0.58 BASE
Adjustment to capital cost	none	none	none	0.9 BASE	none	none
Adjustment to variable O&M cost	none	none	none	0.9 BASE	none	none
Adjustment to fixed O&M cost	none	none	none	0.9 BASE	none	none
Adjustment to station use	none	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE
Adjustment to heat rate	none	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE
Adjustment to forced outage rate	none	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE	0.9 BASE
Domestic gas price ($/mmBtu)	2.3	2.3	3.5	3.5	3.5	3.9
Diesel price ($/mmBtu)	2.86	2.86	5	5	5	5.6
Imported coal price ($/mmbBtu)	3.25	3.25	3.25	3.25	3.25	4.25
Imported gas price ($/mmBtu)	4.55	4.55	4.55	4.55	4.55	4.95
Domestic coal price ($/mmBtu)	1.01	1.01	2.5	2.5	2.5.	3.5

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A lack of energy is seriously curtailing economic growth in developing countries and countries in transition. Expansion of energy supplies imposes a huge financial burden while increasing environmental threats in these countries. In addition, many countries lack the institutional capability and appropriate technology to operate and manage energy systems efficiently. These factors contribute to the role energy development plays as a leading contributor to global climate change and regional and local environmental problems.

To address these problems, the Office of Energy, Environment, and Technology leverages the financial resources of multilateral development banks, such as The World Bank and the InterAmerican Development Bank, the private sector, and other bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research and adaptation. These approaches include improving power sector investment planning ("integrated resources planning") and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. The Office's promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective growth.

Further information regarding Center for Environment and Office of Energy, Environment, and Technology activities can be requested by contacting the Office of Energy, Environment, and Technology at the following address.

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