ASSESSMENT OF POWER SECTOR REFORMS IN ASIA
EXPERIENCE OF GEORGIA, SRI LANKA, and VIET NAM

Synthesis Report
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Most of the countries in Asia and the Pacific will see a continually growing demand for electricity due to the rapid growth of their populations and their economies. A strong and more responsive energy and electricity sector will therefore be needed by these countries not only to attain supply security, mitigate the impacts of climate change, and improve energy and electricity access for all but also to achieve more inclusive and environmentally sustainable economic growth. To help improve the power-sector reform planning perspectives of the countries in the region, the Asian Development Bank conducted a study that sought to assess the reform developments in three selected ADB member countries, namely Georgia, Sri Lanka, and Viet Nam, and to look into their comparative success and performance in achieving their targeted power reform outcomes. This synthesis report, *Assessment of Power Sector Reforms in Asia*, analyzes the key aspects of that three-country review, particularly institution-building, regulatory framework reform, structural and functional unbundling of the power sector, deregulation, private sector participation, and tariff settings.

This synthesis evaluates the comparative advantages and disadvantages of the different power-sector reform models adopted by the three countries to achieve their desired economic, social, and environmental outcomes. The criteria used in the evaluation are the commonly agreed and internationally accepted set of Energy Indicators for Sustainable Development: Guidelines and Methodologies released by the International Atomic Energy Agency, United Nations Department of Economic and Social Affairs, International Energy Agency, Eurostat, and European Environment Agency in 2005. Overall, the progress of the power sector reforms in each of the three countries has been a slow and incomplete process, hampered in many cases by political and technical obstacles. In the case of Georgia and Sri Lanka, moving the reform agenda forward needed strong political will to implement the principles and procedures already enacted into law; in the case of Viet Nam, it is still in the process of firming up its road map for power sector reforms. In any case, we believe that the key findings and lessons of the country reports for Georgia, Sri Lanka, and Viet Nam will provide other ADB member economies with insights for better power-sector planning and decision making and for improving policy and strategy formulation. They should also serve as invaluable guidance in improving ADB’s country and regional energy operations and assistance.

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ABBREVIATIONS

ADB — Asian Development Bank
BOT — build-operate-transfer
CEB — Ceylon Electricity Board
$\text{CO}_2$ — carbon dioxide
E VN — Viet Nam Electricity
ESCO — Electricity System Commercial Operator
GDP — gross domestic product
GEL — lari (Georgian currency)
GNERC — Georgia National Energy and Water Supply Regulatory Commission
GSE — Georgian State Electrosystem
IAEA — International Atomic Energy Agency
IPP — independent power producer
JSC — joint stock company
LECO — Lanka Electricity Company
MOIT — Ministry of Industry and Trade (Viet Nam)
NCRE — nonconventional renewable energy
OECD — Organisation for Economic Co-operation and Development
PMP VII — National Master Plan for Power Development for 2011–2020 Period with the Vision to 2030
PPA — power purchase agreement
PUCSL — Public Utility Commission of Sri Lanka
SPP — small power producer
UEDC — United Electricity Distribution Company
US — United States of America
USAID — United States Agency for International Development
USSR — Union of Soviet Socialist Republics

MEASURES

GWh — gigawatt-hour
kV — kilovolt
MVA — megavolt ampere
MW — megawatt
TWh — terawatt-hour
Introduction

This report examines three economies in different parts of Asia—Georgia, Sri Lanka, and Viet Nam—that introduced power sector reforms in recent years to create a commercially viable and efficient power sector. The power sector reforms in each of these countries were undertaken as part of a larger overall economic recovery effort. Georgia reinvented itself as an independent and more capitalist country with planned links with the European Union; Viet Nam made great strides with Doi Moi, its far-reaching economic reform program, and with the wider opening-up of its economy; and Sri Lanka, following a lengthy civil war, decided to pursue a much-needed program of reconstruction.

The reform process in all three countries have entailed measures designed to (i) restructure the power sector to allow the entry of competition, (ii) improve regulation of the power sector, and (iii) create the preconditions for the effective implementation of those two measures. The three countries each gradually instituted preconditions for reform and for creating an efficient and profitable power sector, then started pursuing efforts to restructure both the power industry itself and its governance.

Reforming the power sector typically begins by departing from the single public utility model for operating it, according to the following four-fold categorization based on degree and on the form of competition that emerges:

Model 1: Monopoly. There is no competition at all, only a vertically integrated monopoly at all levels of the supply chain.

Model 2: Single buyer or purchasing agency. To encourage competition between different power producers, a single buyer or purchasing agency is allowed to choose its sources of electricity from among electricity producers. This agency then sells the electricity to distribution companies and to large power users without competition from other suppliers.

Model 3: Wholesale competition. This model allows distribution companies to purchase electricity directly from the power producers they choose, either through bilateral contracts or from a power pool. The distribution companies transmit this electricity under open-access arrangements over the transmission system to their service area, then deliver it to their customers through their local grids.

Model 4: Retail competition. This model allows all customers to choose from among different electricity suppliers, who are given open access to the transmission and distribution systems.

Of the three countries, Georgia is the only one that chose the wholesale competition model; both Sri Lanka and Viet Nam chose to operate under the single-buyer model. Each of them took a different route in moving away from a monopoly state-owned utility. Georgia's key focus was to attract private capital and management expertise to the power sector concurrently with efforts to restructure and privatize it. Sri Lanka chose to operate under the single-buyer model so it can reform the finances and governance of its power sector at least initially as a state-owned monopoly. Since then, in both Georgia and Sri Lanka, foreign investments have
greatly facilitated repair of war-damaged facilities as well as the construction of new generating plants. In Viet Nam, however, the entry of foreign investments has been hampered by the complexities in distributing the assets, revenues, and financial obligations of its public sector utility, Viet Nam Electricity (EVN), that arose when the government unbundled it, thus creating an insufficiently clear environment for investors to provide the needed new capacity.

**Power Sector Reform in Georgia**

From 1921 to 1991, when Georgia was one of the 15 republics of the Union of Soviet Socialist Republics (USSR), its power sector was an integrated part of the USSR grid. After independence in 1991, however, the political chaos and conflict that ensued in Georgia led to a deep economic recession that seriously affected the national power system, which was then being run by Sakenergo, a vertically-integrated state-owned monopoly. Countrywide blackouts became frequent as power generation fell from 14.240 billion kWh in 1990 to 7.074 billion kWh in 1995.

After Georgia’s economy stabilized in 1995, the first phase of the country’s power reform began with the creation of a body to regulate wholesale and retail tariffs, the Georgian National Electricity Regulatory Commission (GNERC). In 1996, the vertically-integrated utility was then restructured into three financially independent subsectors, namely generation, transmission and dispatch, and distribution, but all within Sakenergo as the larger holding company. Generation and distribution functions were taken out from Sakenergo. The generation function was taken over by joint stock companies under a holding company called Sakenergo Generatsia, while management of the distribution system was transferred to 66 municipal distribution companies, under the control of their respective local municipalities. Transmission and dispatch activities remained under Sakenergo.

When Georgia’s power sector was unbundled in 1996, the Ministry of Energy was reestablished to oversee the reforms and the Georgian Wholesale Electricity Market (GWEM) was created. Privatization was then pursued principally by inviting foreign investment, with the distribution system attracting initial interest. In 1998, the American company AES bought 75% of the shares of JSC Telasi, the distribution company in Tbilisi, for US$25 million. This first major privatization in Georgia’s power sector was a turning point that was followed by further foreign investments.

Transferring the distribution function to foreign companies was then seen as a means of introducing modern management skills to the power sector, so, on the advice of the International Finance Corporation (IFC), the remaining power distribution companies in Georgia were merged to make them attractive to prospective foreign investors. It was on this basis that in 2001, management of the single buyer GWEM was transferred to the Spanish company Iberdrola for a period of 5 years under a management contract sponsored by the European Bank for Reconstruction and Development.

In 2002, Georgia’s electricity transmission company and electricity dispatch company, both created after the dissolution of Sakenergo, were merged into the Georgian State Electrosystem (GSE). The following year, the GSE was placed under a 5-year management contract with an Irish company, Electricity Supply Board Ireland. These institutional changes are deemed to have helped reduce corruption and improve financial and technical performance by introducing the expertise of international companies into the power sector.

After parliamentary elections in Georgia in 2004, general reform measures were instituted throughout the economy. In 2005, the government injected several hundred million dollars into the power sector for the rehabilitation of state-owned assets for generation, distribution, and transmission. In December of that same year, approval of market rules was transferred from the regulator (GNERC) to the Ministry. In what appeared to be a move meant to weaken the mandate of the regulator, the Ministry of Energy was also authorized to issue technical rules, approve power and natural gas balances, and make decisions about deregulation and
partial deregulation. In 2006, to create a competitive wholesale market, the single-buyer GWEM was replaced by the Electricity System Commercial Operator (ESCO), under whose aegis the power generators, distribution companies, direct customers, and exporters in Georgia were allowed to enter into direct contracts, with ESCO buying and selling balancing power and reserve capacity.

In summary, the reform process in Georgia has resulted in an unbundled and largely privatized power sector that has an operational wholesale market. Great progress has been achieved in making system pricing more efficient and in developing the sector’s commercial viability, but Georgia’s power sector still lacks transparency in pricing and in independent regulatory competence. Generation, transmission, and distribution companies in Georgia today often have the same owners, or form part of the same vertically integrated company. Even if legal and regulatory requirements for transparent, reliable and competent regulation are in place, there has been a recent concern that the independence of the regulator has been overridden by political decisions; this is despite the current government’s publicly stated commitment to a genuinely independent regulatory system. A key weakness that has been identified thus far is lack of transparency in tariff-setting, for a number of transactions have not been covered by promulgated tariffs and the costs behind them have not been publicly disclosed.

**Power Reform in Sri Lanka**

Sri Lanka’s power sector initially operated under a government department. In 1969, however, it was placed by the Ministry of Power and Energy under a public sector utility, the Ceylon Electricity Board (CEB), which made the power sector a vertically integrated monopoly carrying out all the functions of generation, transmission, distribution and retail supply with no competition at any level. As a modest move away from this structure, a state-owned distribution company, Lanka Electricity Company (LECO), was established in 1983 to distribute power in designated areas previously served by local authorities and municipal councils. In 1996, private sector participation in power generation started, with independent power producers (IPPs) and small power producers (SPPs) allowed to supply electricity to the grid.

Between 1995 and 2001, several studies and consultations were undertaken to develop a more profound restructuring and reform of Sri Lanka’s power sector. In 2000, through its own administrative decision, the CEB internally unbundled itself into generation, transmission, and four distribution divisions but without legally or financially separating these divisions from the CEB. Then, in July 2003, the Public Utilities Commission of Sri Lanka (PUCSL) was established as a regulator for public utilities in the energy and water sectors, but it was only in 2009 that the PUCSL was fully empowered to regulate the power sector, under the purview this time of Sri Lanka’s revised electricity act, Electricity Act No. 20 of 2009. However, this revised act introduced less restructuring of the CEB than had been originally proposed. A single-buyer model was introduced, with the CEB transmission entity as the single buyer, but the business units or divisions within CEB’s vertically integrated utility were not made separate entities with independent ownership structure and management. Thus, CEB currently holds one generation license (covering about 66% of all generating capacity in the grid), one transmission license (covering 100% of transmission and 100% of bulk supply in accordance with the single-buyer model), and four distribution licenses (in total accounting for approximately 90% of customers).

In 2009, the PUCSL started discussions with licensees on a new tariff methodology to unbundle rates as well as to address the issue of transfer prices and subsidies. Over the years, the CEB had accumulated large debts as a result of subsidies established by government policy; these debts now needed to be dealt with. In principle, under a new tariff methodology that became effective in January 2011, the tariff schedule should henceforth separately reflect the costs of each licensee for power generation, transmission, and distribution. However, the full implementation of this methodology has been delayed, thus exacerbating the CEB’s weak financial position. Likewise still lacking is a truly independent regulation and operation of the system, which is essential for tariff reform. Until then, neither the PUCSL nor the CEB can make independent decisions,
particularly politically unpopular moves, without the possibility of being blocked by government interference. The result was a nontransparent and at times distortionary process of decision making.

Power Reform in Viet Nam

Before 1995, Viet Nam’s power sector was government-owned, with the Ministry of Energy managing three regional power companies that were each responsible for generation, transmission and distribution within their respective territories. Some restructuring began as early as 1995, with the creation of Electricity of Viet Nam (EVN), a utility that reflected a broader reform program, the Doi Moi, that began in 1986. As early as 2000, however, the breakup of the EVN monopoly already started with the introduction of non-EVN generating capacity through independent power producers (IPPs). In that year, IPPs accounted for some 7% of total capacity (452 MW) and about 9% of total generation (2.51TWh). In 2003, the government began the partial restructuring of EVN. In a process referred to in Viet Nam as equitization, several generation and distribution assets were corporatized into joint stock companies and their shares sold to other government-owned companies. The following year, in 2004, it was proposed that EVN should retain full ownership and control of the three large multipurpose hydropower projects (about 30% of installed capacity) but that its remaining eight generation plants (another 48% of total capacity) would be subject to equitization.

The road map for power reform in Viet Nam is clear. It originally envisioned the following: (i) an initial pilot stage with limited competition among selected state-owned generators, with a single buyer to be introduced by 2009; (ii) the creation of a competitive wholesale market by 2017; and (iii) a competitive retail market by 2024. Its implementation, however, has slipped from this schedule. The pilot competitive generation market started only in 2012. An updated road map issued in November 2013 now envisions the start of a competitive wholesale market by 2015 and its full operation by 2017, then moving on to a likewise fully competitive retail market by 2023.

The National Power Transmission Corporation (NPTC) was established in 2008 based on the reorganization of four transmission companies and three power-grid management boards within EVN. Owned 100% by EVN, it is responsible for managing the transmission grid. Also established in 2008, the Electricity Power Trading Company (EPTC) is also part of EVN and plays the role of single buyer in the generation market. The system operator, the National Load Dispatch Center (NLDC), is also part of EVN, but it is intended to be ultimately separated from EVN and become independent with the start of the competitive wholesale market. In 2010, the 11 existing regional distribution companies within EVN were reorganized into 5 power corporations. All single-owner limited companies owned 100% by EVN, they are responsible for supplying power and maintaining the distribution grid up to 110 kV over five areas of the country.

In 2012, the EVN’s generation operations were reorganized into three power generation companies. These are single-owner limited companies initially 100% owned by EVN and operating as divisions within EVN’s structure as a holding company. They are to be fully separated from EVN when the competitive wholesale market begins, and the ultimate goal being is to seek private investment in these companies. On the other hand, the EVN will retain ownership and operating control over three strategic multipurpose hydro projects whose operations have implications for irrigation and flood control. As to market development for Viet Nam’s power sector, electricity trading is currently carried out either through definite-term contracts or through spot trading. In 2012, a small pilot competitive generation market started, so that power generating companies and IPPs now compete in a power pool to sell to the single buyer (EPTC). As of now, however, only 10% of sales are made at spot market prices, with 90% of sales at prices negotiated in contracts between the generator and the single buyer.
Viet Nam’s reform process to date has instituted the functional unbundling of the industry’s monopoly structure, along with some institutional, regulatory, and pricing reforms. EVN has theoretically been unbundled and is now a holding company with a number of operating divisions that are not yet fully independent. Some tariff reform has been introduced to provide cost-based rates, but as in the case of Georgia and Sri Lanka, the traffic adjustments have been delayed. A high proportion of sales are still covered by long-term financial PPA contracts, with nontransparent prices that have been negotiated between power generators and the government. The Electricity Regulatory Authority of Viet Nam (ERAV) continues to have a limited advisory role, and is authorized only to assist the government in regulating the operation of the power market. In sum, the government retains a strong vested ownership and management interest in the power sector, making independent regulation virtually impossible under current conditions.

**Postreform Outcomes in Georgia, Sri Lanka, and Viet Nam**

In assessing the outcomes of power sector reform in Georgia, Sri Lanka, and Viet Nam, it is virtually impossible to isolate with confidence the efficiency gains that resulted specifically from and solely due to power sector industry restructuring and reform, from gains arising from overall economic development or from general economic reform. However, it is possible to establish the postreform position by charting the trends in indicators that reflect aspects of economic, technical, social, and environmental performance relative to a prereform base year (which differs between country cases). A broad perspective on postreform outcomes, but without attribution to direct causation, can be gleaned clearly from this comparison of data from the most recent year available (usually either 2013 or 2012) with those of the base year.

The broad picture that emerges from this experience is that the power system of each of the three countries was able to expand, thus ensuring that the rising demand created by income growth could be met without rationing power. In each country, electricity consumption per capita increased relative to the base year. It increased by eightfold in Viet Nam and by more than threefold in Sri Lanka. The 32% increase in Georgia is much more modest and it is accounted for by the decline of the industrial sector, which led to a major structural change in the country’s economy.

In each of the three countries, transmission and distribution losses were reduced significantly owing to improved technical efficiency. Georgia’s losses were no more than 10% of the prereform levels, Sri Lanka’s were roughly 50%, and Viet Nam’s 40%. In Viet Nam and Sri Lanka, the electricity intensity (defined as electricity consumption over GDP) has increased with growing industrialization and with industry’s growing share in GDP. The increase in electricity intensity is very marked in Viet Nam, whose intensity ratio is now more than three times the prereform level; Sri Lanka’s electricity intensity was roughly 25% higher. However, Georgia’s electricity intensity in 2013 was roughly 65% lower than the prereform level, a performance that is strictly not comparable because the country underwent de-industrialization after its Soviet period.

In social terms, electrification rates are high in all three countries. This is true even for Sri Lanka and Viet Nam even at their higher income levels, although in their case most of the electrification rate increases were instituted before the power reform period. In terms of affordability, Georgia has the cheapest power in terms of the share of electricity cost in household income, although the figures are not directly comparable across the three countries; this is particularly true with the electricity data for Viet Nam, which include some non-electricity expenditure. What is clear is that the power sector reforms in these three countries have not caused a major rise of household electricity costs in average-income homes. On average relative to the prereform period, the share of electricity expenditure in income fell by about one-third in Georgia and by around 8% in Sri Lanka, but went up by about 30% in Viet Nam. The share of electricity expenditure in the income of the poor has risen in Viet Nam in recent years, but has fallen in Sri Lanka. For the poorest 20% in these two countries, however, available data suggest that reform has not been associated with a significant rise in the share of electricity cost in their income.
The environmental impact on the three countries varied widely as a result of changes in the structure of their respective power generation sectors. In Georgia, there was a minimal 10% rise of greenhouse gas emissions from electricity production per capita relative to the prereform base year. The rise was very substantial in Sri Lanka and Viet Nam, however, reflecting the shift away from renewables in the total generation mix in these countries. While the share of renewables in the most recent year was roughly 90% of the prereform level in Georgia, it was around 55% of the prereform position in both Viet Nam and Sri Lanka. Georgia’s reliance on hydropower creates other issues, security of supply among them. This is because during years of drought, it is highly vulnerable to fluctuations in international markets as it needs to balance shortfalls in hydropower generation with imports of power and imports of gas for its thermal plants.

Lessons Learned and the Way Forward

Power sector reform in Georgia, Sri Lanka, and Viet Nam has been a relatively slow and partial process, with many obstacles of both political and technical nature getting in the way. Reforms that have been put in place are often restricted or blocked by vested interests in the sector, by consumer sensitivities, by a relatively small market size, and by the difficulties of attracting private finance. As a result, the desired reforms have not kept to the original road maps and their timing and implementation schedules are often disrupted by political decisions.

In Sri Lanka and Viet Nam, the unbundling of the power sector has been largely functional, leading to the creation of separate but not independent units or companies within a larger public sector holding company. There is therefore continued strong government involvement in power sector management and operations. Even in Georgia, despite its high degree of divestiture, there is serious concern over re-bundling within the private sector because large utilities with interlocking ownership have often moved to consolidate their operations, supplies, and markets.

Nominal tariff reform has been promulgated in all the three countries, but they have not been fully implemented. Since the tariff design is often not transparent, it is extremely difficult to find out where distortions might lie, or if revenues can cover the costs. Well-known tariff distortions, such as special privileges for specific customer classes and renewable tariffs that have been found to be unsustainable, need to be reviewed and revised accordingly.

In all three countries, IPPs were encouraged because private investment was needed in the face of restrictions on government to fund new capacity. But in none of these countries are these IPPs contributing to the strengthening of competition among generators. On the contrary, these IPPs are granted power purchase and operating contracts that are negotiated without transparency. Indeed, where some transparency does exist as to IPP feed-in costs, as in Sri Lanka, these feed-in costs have been found to be well above the system average.

On the whole, the power sectors in Georgia, Sri Lanka, and Viet Nam each need continuing improvements in transparency, in economic efficiency, and in regulation, particularly in tariff-setting, system management, and effective independent regulation. Efficient pricing and good governance are now being addressed effectively, if only in part, but the preconditions for real competition in the power sector still need to be put firmly in place in these countries.
1. INTRODUCTION AND OVERVIEW OF POWER SECTOR REFORM

This report examines the cases of three economies from different parts of Asia—Georgia, Sri Lanka, and Viet Nam—that have introduced power sector reform in recent years. Power sector reform entails a major commitment to economic and political change. It is generally and most successfully undertaken not as a matter of political ideology but in response to economic and market pressures and a need for change. The general goal is to create a commercially viable and efficient power sector. Specific goals include, primarily and necessarily,

• improving the economic efficiency and profitability of the power sector;
• improving regulation to provide good governance and equitable service;
• insuring transparency in pricing, management, and regulation; and
• assuring the physical security and reliability of supply.

The purpose of this report is to assess, to the extent possible, the outcomes of the power sector reforms. The report focuses on outcomes related to the specific reform goals noted above: improved economic efficiency and profitability of the power sector; improved regulation to provide good governance and equitable service; transparency in pricing, management, and regulation; and physical security and reliability of supply. The assessment is presented partly in statistical indicators reflecting changes in sector performance and in the benefits it delivers, against a backdrop of social and economic change over time.

There are limitations to this analysis. First, rigorous and comprehensive assessment requires rigorous and comprehensive statistics; by and large these do not exist in many countries, the three case study countries being no exception. Typical statistical deficiencies include insufficient historical data, lack of consistent timelines, and definitional problems. Even more significant to the analysis is a lack of transparency in the power sector of all three countries. One may be able to assess improved efficiency of power supply by tracking generation and distribution data. But one cannot begin to assess economic efficiency or improved commercial viability without transparent data on pricing and costs, or without the operation of developed capital markets publicly tracking performance of private companies.

Second, the goals of economic development and of power sector reform go hand-in-hand. In each of the countries studied, power sector reform was undertaken as part of a larger over-all economic recovery effort. Georgia has been reinventing itself as an independent and more capitalist country; Sri Lanka is pursuing a program of reconstruction following its civil war; Viet Nam has made great strides under its far-reaching economic reform program, Doi Moi. In assessing the outcomes of reform in these countries, it is virtually impossible to isolate with any confidence the efficiency gains that have resulted specifically and solely due to power sector industry restructuring and reform from gains due to over-all economic development or general economic reform. For example, widespread electrification took place in all three countries prior to power sector reform. In another vein, while there has been a major reform focus on divestiture to change ownership patterns from state-owned to
privately held companies, efficiency gains cannot be directly ascribed to these reforms without knowing what would have happened under continued public ownership.

There are, of course, a few exceptions. In one such exception, in the case of Georgia, there were identifiable and major improvements in power sector finances as a direct result of hiring foreign private management firms for several of the largely state-owned power sector companies. A significant inference to be drawn from this case is that who owns the industry is not nearly so important for performance as how it is run. State-owned utility companies in members of the Organisation for Economic Co-operation and Development (OECD) offer similar examples of efficiently operated and profitable enterprises.

The experience of each country, summarized in the following chapters and available in individual country reports (ADB 2015a, b, c), represents a broad spectrum of power sector reform efforts, experiences, and relative successes. For the most part, they do not present dramatic outcomes and signal intent more than implementation. The country experiences show a political willingness to change and earnest efforts at power sector reform as it can best be implemented given local conditions. The report considers the context in which reform was introduced in each country, the details of their programs, the obstacles they have faced, and the aspects that remain to be implemented (Chapters 2 to 4). The evolution of the power sector in each country is partly assessed using a series of indicators that reflect the economic, social, and environmental impacts of the sector in the periods prior to and since reform (Chapter 5).

After considering lessons learned, the final chapter (Chapter 6) offers a perspective on the direction future power sector reforms might take. It does so by briefly highlighting significant elements or conditions that have been essential to such reform in OECD countries, and that might ultimately be appropriate for future reform in the three study countries as well.

1.1. Preconditions for a Successful Reform

No single approach is appropriate to power sector reform in all countries. But the two essential preconditions for reform to succeed include assuring economic efficiency and viability of the power sector, and establishing good governance. These should precede any effective restructuring or attempts to introduce competition. How to best create these preconditions will depend on the circumstances of a particular national power sector. National conditions thus must play an important part in the design of power sector reform.

A reform process suitable for developed economies with large and varied power sectors and developed capital markets may not work at all in a developing country lacking either or both. For example, for decades in most developed countries electricity companies were monopolies, which permitted secure and sufficient investment for system expansion. These monopolies were dissolved only when market conditions no longer required the benefits they offered. The market structure that is suitable for the stage of economic and political development of a given country and the size and features of the power system should be decided on for that country. For example, in countries experiencing deep and prolonged economic and political crises and focusing on stabilization, trying to introduce sector unbundling, competitive markets, and privatization for the power monopoly can be counterproductive.

Having a competitive power sector is one way to achieve at least some reform goals. Competitive markets tend to be self-correcting, and so competition is generally agreed to come closest to assuring efficient system investment and operation. Introducing competition where none exists is therefore one focus of power sector reform in many countries. However, this cannot be done by promulgation or decree. Competition cannot exist unless the prerequisite conditions are in place:
• a considerable number of market players so that no one player can influence market price, volume, or conditions;
• players that are well-informed about prices and costs—each player must have the choice to participate in the market or not, and must be able to determine how to participate; and
• market players that are economically viable and commercially sound.
The rule of law and transparent market conditions are also crucial.

In many cases, creating competition suggests a need for privatization, though this is not necessarily the case. For example, a government contracting with any number of privately held independent power producers (IPPs) does not promote competition if the IPPs operate under long-term and preferential power purchase agreements that are not transparent and are negotiated. This has been a problem in OECD countries as well as in all three case study countries. Moreover, to be effectively privatized, an entity should be commercially viable. Otherwise, private investment will be difficult to attract. In fact, neither competition nor privatization can be introduced successfully without first achieving commercial viability. Nor is it easy to introduce privatization and commercial viability at the same time, as they create different expectations and demands for market players. If privatization is the prime objective, then vertically integrated monopolies, operated efficiently, make attractive targets for investment, and the prospect of future competition may deter investors. Similarly, if competition is the prime objective, concurrent privatization can be difficult, because the conditions of operation and the potential for profit on which the private investment is predicated will change with competition.

Market restructuring based on competition and privatization is not the only road available to reform. Power sector regulation in and of itself is an essential and powerful tool for changing power sector performance. Regulation can be used to approximate the benefits of competition, or to create conditions for its development. However, just as for competition, certain conditions must be present for regulation to be effective. While the over-all design of reform will vary with each country, certain regulatory criteria are essential: regulation should be consistent, well-informed, transparent, technically suitable, neutral, fair to all parties, and free from corruption and political whim. All three countries studied are attempting to improve the governance of their power sectors, although their efforts are often complicated by political considerations.

The reform process in all three countries—Georgia, Sri Lanka, and Viet Nam—includes measures to restructure the power sector to introduce competition, improve power sector regulation, and create the preconditions for their effective implementation. The variety of measures promulgated and implemented in the three countries, the efforts in restructuring both industry and governance, and the plans for future changes all constitute the gradual institution of preconditions for reform and crucial steps toward creating an efficient and profitable power sector.

1.2. Models of Reform

Power sector development goes hand-in-hand with socioeconomic growth. When poor economic and technical performance result in financial and technical losses in the power system, creating an inability to finance maintenance and investment, there is a strong need to reform the power sector’s finances, regulation, and management. To simplify the exposition and allow generalizations across countries, distinct phases in the development of the power sector can be identified. In the basic phase, utilities tend to be vertically integrated monopolies, often state-owned, and operated as government departments with little commercial focus. In the second phase, they progress to become commercially viable and socially responsible public sector companies operating fully on commercial lines, covering their cost of supply, including the cost of capital. In the third phase, they become privately owned competitive entities. In many developing countries, power sector structure is still in the basic stage, dominated by a state-owned national
power utility with a legally endowed monopoly and a vertically integrated supply chain. Internationally within the public sector, attempts at leapfrogging from the basic to the third phase have not had much success.

Alongside these broad stages, a four-fold categorization based on the degree and form of competition that emerges is often used:

- **Model 1—monopoly**—has no competition at all, only a vertically integrated monopoly at all levels of the supply chain within a country or a region.

- **Model 2—single buyer or purchasing agency**—allows a single buyer or purchasing agency to encourage competition between generators by choosing its sources of electricity from among electricity producers. The agency sells electricity on to distribution companies and large power users without competition from other suppliers.

- **Model 3—wholesale competition**—allows distribution companies to purchase electricity directly from the generators they choose, either by bilateral contracts or from a power pool; transmit this electricity under open access arrangements over the transmission system to their service area; and deliver it on their local grids to their customers. This brings competition into the wholesale supply market but not the retail power market.

- **Model 4—retail competition**—allows all customers to choose their electricity supplier, which implies full retail competition, under open access for suppliers to the transmission and distribution systems.

Such models of competition have figured in plans for reform in the three case study countries. Power sector reforms in developing countries have tended to try to emulate the experience, evolution, and conditions of commercially competent, more developed, and mature power sectors. The reforms generally include measures to restructure the industry to attract private investment, with varied mixes of unbundling, ownership, degrees of competition, and forms of regulation, and to introduce competition. Such reforms often first encourage competition among generators selling to a single buyer, then permit first wholesale customers and then retail customers to choose their suppliers. This is the path preferred in many developing countries, including the three study countries. But the preconditions for competition and privatization do not exist in many of these countries. The overarching requirements of good governance and especially of economic efficiency are largely lacking, including the need to allocate investment; provide maintenance; and be profitably self-sustaining, and independent from government debt. Without them, the mere act of restructuring is not likely to produce desired results (Krishnaswamy and Stuggins 2003). Nor is privatizing companies the easiest path to commercial success, because investors are most likely to be attracted to companies that are already commercially viable, offering a potential for profit and for recovery of investment. There is no simple way to transform an inefficient power sector into a set of viable competing enterprises.

The appropriate mix of reform elements in any given country will depend, among other things, on the size of the system, the role the private sector (such as IPPs) plays in the market, the initial degree of efficient pricing, the degree of transparency in pricing and regulation, and the quality of power sector governance. For example, unbundling may not be appropriate for small systems not readily susceptible to competition. Where IPPs form a large part of the generating market, introducing competition and especially introducing efficient pricing under a single buyer can be frustrated by power purchase agreements that are rigid or preferential or by take-or-pay agreements. Competition can also be frustrated in wholesale markets without regulation to prevent nonpayment, or where supply and demand are preferentially allocated. Other important factors for the success of power sector reform include the institutional capacity of the economy, the general investment climate, and the political backing for the sorts of changes that reform will introduce.
1.3. Power Sector Reforms in Selected Countries

Power sector reforms in the three countries complement efforts of the Asian Development Bank (ADB) to achieve one core area of its Strategy 2020 (ADB 2008). ADB promotes institutional and policy reforms to enhance the operational efficiency and sustainability of energy operations and infrastructure in its developing member countries (DMCs). In the last 40 years, ADB has been providing assistance to its DMCs in the energy sector, particularly on power expansion programs and infrastructure, institutional capacity building, power sector reforms, governance, and efficiency improvements. From 1990 to 1995, ADB invested largely in transmission and distribution, sector development, and power generation. Since 2000, it promotes power sector restructuring to improve efficiency and to attract private investments.\(^1\)

In the specific cases of the three study countries, reforms have led to some advances in power sector development, and these are considered here. At the same time, shortcomings in policy implementation must be noted with respect to the scope, pace, and sequencing of the reforms. The primary factors affecting these shortcomings include weak initial starting conditions for implementing reform; fiscal pressure, especially disenchantment with the poor performance of publicly-owned utilities; and weak governance of the power market. These factors are considered in further detail, against the background of broader experience in power sector reform.

The three selected economies and their power sectors differ considerably. Georgia has a much smaller population than the other two countries. The average income per capita in Georgia (in current prices at market exchange rates) is roughly double that of Viet Nam and 20% above that of Sri Lanka, but the poverty rate is also much higher. Georgia and Sri Lanka belong to countries of high human development, ranking 79th and 73rd, respectively, of 187 countries, while Viet Nam belong to medium human development and is ranked 121st. Table 1.1 summarizes the basic indicators, the main source of generation capacity, and the current reform situation in each country. Hydropower generation is significant in all three countries, although to a lesser degree in Sri Lanka with the rapid development of thermal generation in recent years. Georgia is the only country with established wholesale competition, while Sri Lanka and Viet Nam operate a single-buyer model.

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**Table 1.1: Country Cases—Basic Indicators, 2013**

<table>
<thead>
<tr>
<th>Country</th>
<th>Population (millions)</th>
<th>Income per Capita (constant 2005 $)</th>
<th>Poverty Rate (at $1.25 a day, % of population)(^a)</th>
<th>Human Development Index</th>
<th>Generation Capacity (MW)</th>
<th>Main Source of Generation Capacity</th>
<th>Current Reform Situation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Georgia</td>
<td>4.5</td>
<td>2,157</td>
<td>17.99 (2010)</td>
<td>0.744</td>
<td>3,339</td>
<td>Hydro</td>
<td>Wholesale competition</td>
</tr>
<tr>
<td>Sri Lanka</td>
<td>20.5</td>
<td>2,004</td>
<td>4.11 (2010)</td>
<td>0.750</td>
<td>3,362</td>
<td>Hydro</td>
<td>Single Buyer</td>
</tr>
<tr>
<td>Viet Nam</td>
<td>89.7</td>
<td>1,029</td>
<td>16.85 (2008)</td>
<td>0.638</td>
<td>28,737</td>
<td>Thermal</td>
<td>Single Buyer</td>
</tr>
</tbody>
</table>

MW = megawatt.

\(^a\) The latest available poverty rates of Georgia and Sri Lanka are 2010; that of Viet Nam is 2008.

The three country cases reveal a similar focus—to restructure state-owned utilities in order to ultimately create a commercially viable and efficient power sector with assured physical security and reliability of supply, although each country has chosen different ways to approach these goals. In relation to improved economic efficiency in Georgia, the key focus was on attracting private capital and management expertise to the sector in the context of a concurrent system restructuring and privatization. In Sri Lanka the decision was made to reform the finances and the governance of the power sector at least initially within the context of a state-owned monopoly. In both countries, foreign investment has facilitated the repair of war damage and construction of new generating plants.\(^2\) In Viet Nam, foreign investment has been frustrated by the complex distribution of assets, revenues, and financial obligations arising from unbundling the Electricity of Viet Nam, creating an environment that is insufficiently clear to attract investors for the needed new capacity.\(^3\)

The limitations to reform are also quite similar. First, particularly in Sri Lanka and Viet Nam, unbundling has been largely functional, creating separate but not independent units or companies within larger public or private holding companies, and with continued strong government involvement in managing and operating the power sector. Even in Georgia, despite a high degree of divestiture, there is serious concern about rebundling within the private sector as large utilities with interlocking ownership move to consolidate their operations, supplies, and markets. Second, nominal tariff reform has been promulgated, but not fully implemented. Tariff design without transparency makes it impossible to know where distortions might lie, or if revenues cover costs. Known tariff distortions—special privileges for specific customer classes, and renewable tariffs now found to be unsustainable—need to be revised and are being reviewed to this end. Finally, IPPs in all three countries were encouraged as private investment was needed in the face of restrictions on the government’s ability to fund new capacity. But in none of the three countries do IPPs contribute to competition among generators. Rather, the IPPs have power purchase and operating contracts negotiated without transparency; where some transparency exists as to IPP feed-in costs, they have been found to be well above the system average.\(^3\)

Finally, the major obstacles and remaining problems to be solved are similar in all three countries studied. In all three, improvements continue to be needed in transparency; economic efficiency; and effective regulation, including tariff setting and system management. The preconditions of efficient pricing and good governance are only partly being addressed effectively and the preconditions for real competition still need to be created.

Table 1.2 summarizes the present market structure and legislation in the three countries.

\(^{2}\) Delayed investment in war-affected regions also weighed on the power sector.

\(^{3}\) Albeit, a majority of the IPPs in Sri Lanka have been procured competitively.
1. Introduction and Overview of Power Sector Reform

Generation assets have been privatized except for Enguri and Vardnili, which are regulatory plants. Also, Enguri is situated on a politically-contested land.

Three companies are involved in transmission: (i) Georgian State Electrosystem is state-owned, which also established Energo Trans for the construction of a transmission line to Turkey; (ii) JSC Sakrusenergo is 50% state-owned and 50% owned by Inter RAOUES; and (iii) JSC Energo-Pro Georgia.

All distribution companies have been privatized except for the Abkhazia Energy Company, which is outside the government’s control.

Generation companies can sell directly to distribution companies, direct customers, and exporters. The Electricity System Commercial Operator buys and sells the balancing power.

### Reform Phase 1

### Reform Phase 2
- Amendment to the Law on Electricity and Natural Gas (26 amendments after 2003), 27 December 2005.

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### Table 1.2: Power Sector Structure at a Glance—Three Country Cases

<table>
<thead>
<tr>
<th>Country</th>
<th>Generation</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Market</th>
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</thead>
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<tr>
<td>Georgia</td>
<td>Generation assets have been privatized except for Enguri and Vardnili, which are regulatory plants. Also, Enguri is situated on a politically-contested land.</td>
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<table>
<thead>
<tr>
<th></th>
<th>Generation</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Market</th>
<th>Relevant Laws and Policies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sri Lanka</td>
<td>Generation, transmission, and distribution have been unbundled into functional business units but are still under the state-owned Ceylon Electricity Board (CEB). Each CEB entity has been issued a license—distribution receiving four licenses—and each is regulated separately. The Electricity Act of 2009 allows private participation in the generation and distribution subsectors provided that (i) the government (directly or indirectly) holds shares for generation licenses with more than 25-megawatt capacity, and (ii) the government holds more than 50% shares of distribution licenses. Sri Lanka employs a single buyer model. Generators only sell to the transmission licensee. The transmission licensee buys from generators and sells to distributors without profit or loss. Initially, competition was limited as transactions were based on power purchase agreements (PPAs). Since 2009, competition is introduced as new PPAs are based on approved plans and competitive bidding. The Public Utilities Commission of Sri Lanka regulates the licensees.</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>There are 9 privately owned major thermal power plants; a majority of installed capacity still belongs to the government. In 2013, the CEB accounted for 68% of installed capacity and 73% of gross generation. Players: the CEB owns 17 hydro, 6 thermal-oil, 1 thermal-coal, and 1 wind projects. Privately owned projects comprise 90 small hydro, 11 thermal-oil, and 14 nonconventional renewable energy entities.</td>
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<tr>
<td></td>
<td>The integrated national grid serves all parts of the country.</td>
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<td></td>
<td>The state-owned Lanka Electricity Company (LECO) buys bulk electricity from the CEB and distributes it to about 10% of all customers. The LECO also holds a separate license.</td>
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*continued*
### 1. Introduction and Overview of Power Sector Reform

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<tr>
<td>Viet Nam</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>
| State utility Electricity of Viet Nam (EVN) has been reorganized as a holding company and renamed Viet Nam Electricity (but retains EVN as its abbreviation). In April 2007, the government directed partial privatization of most of EVN’s operating units engaged in power generation and distribution. | The National Power Transmission Company, an EVN subsidiary, operates and maintains the national transmission grid. | The previous 11 distribution companies have been organized into 5 companies to ensure efficiency of distribution network. | Electricity Regulatory Authority of Viet Nam is tasked to develop and regulate the power markets. | • Power Sector Policy Statement, December 1995, later updated in August 1997.  
• Electricity Law, December 2004.  
• Roadmap for Power Sector Reform, 26 January 2006.  
• Prime Minister Decision No. 63/2013/QD-TTg Revised Road Map and the conditions and organization structure for Viet Nam’s power market development. |
| EVN power plants—except the large multipurpose hydro facilities—are being “equitized” to bring in private capital. |                               |                               |                                             |                             |
| The Electricity Law stipulates that large multipurpose hydro facilities will remain EVN-owned. |                               |                               |                                             |                             |
| Other players: Petro Viet Nam, Vinacomin, independent power producers, and build-operate-transfer projects. |                               |                               |                                             |                             |

Sources: ADB (2015a, b, c).
2. POWER SECTOR REFORM IN GEORGIA

From 1921 to 1991, Georgia was one of the 15 republics of the Union of Soviet Socialist Republics (USSR). In 1991, Georgia became an independent, sovereign republic, although 20% of its territory (Abkhazia and South Ossetia) remains the subject of a territorial dispute. The economy went into a deep recession after the break-up of the USSR, but recovered in 1995 and growth then resumed (apart from a drop in 2008 in response to the global recession). With a gross domestic product per capita of about $3,596 in 2013, Georgia is a lower-middle-income country by the World Bank classification (Figure 2.1).

Georgia has no significant reserves of fossil fuels, although it does produce a small amount of oil and natural gas. The country’s primary energy supply depends on imported natural gas and oil products, with natural gas imported from Azerbaijan and the Russian Federation satisfying 44% of the country’s energy needs in 2012 (Figure 2.2).

Hydropower provides more than 80% of generating capacity for electricity and 75%–90% of electricity supply, depending on rainfall and other conditions. In 2013, hydropower provided 8,271 gigawatt-

Figure 2.1: Georgia—Real GDP Growth 1990–2013 (%)

GDP = gross domestic product.

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4 Information and data on Georgia in this and subsequent chapters come from ADB (2015a) except as otherwise indicated.
hours of electricity—about 82% of total electricity production. The country’s thermal power is fueled by gas imports (Figure 2.3).

Under the USSR, the Georgia power system was an integral part of the South Caucasian United Energy System that served three Soviet republics—Armenia, Azerbaijan, and Georgia—and was partly controlled from the Regional Dispatch Center in Tbilisi, Georgia. With independence in 1991, Georgia

endured a period of chaos with high inflation, civil conflict, and the displacement of a large part of the population. Consequently, the economy shrank by nearly three-quarters between 1990 and 1994.

The political and economic situation began to stabilize in 1995, with presidential and parliamentary elections, the adoption of a new constitution, and international recognition as an independent state. Five years of economic downturn were reversed, inflation was reduced, a new currency (the lari) was established, and positive growth of gross domestic product resumed. To sustain economic growth, the government committed to instituting reforms to achieve electricity supply security.

2.1. Background to Reforms

During the USSR times, Georgia’s national power system was run by Sakenergo, a vertically-integrated state-owned monopoly. After independence in 1991, Sakenergo no longer enjoyed Soviet-era subsidized transfers for fuel and power. As the government tried to improve service without sufficient revenues, the utility incurred large payment arrears, mainly for imported fuel and power. Exporting countries cut Georgia’s gas supply for lack of payment, and thermal plants were shut down. Moreover, many power plants were damaged during the civil conflicts. The result was countrywide blackouts and limited power
supply, although power imports continued. By 1994, there were 150 disconnections in the transmission system. Generation fell from 14,240 billion kilowatt-hours (kWh) in 1990 to 7,074 billion kWh in 1995; imports also declined. Electricity consumption was at its lowest in 1997 at 73 billion kWh, 42% of the average consumption in 1990. Centrally supplied heating and hot water were no longer provided.

Distribution and supply of electricity to the various regions was uneven, with the capital Tbilisi receiving a major share. Even in Tbilisi, in 1998, electricity was only available for 4–6 hours a day; in most other regions it was available for only 3–4 hours, with priority given only to establishments of critical importance such as hospitals, military and police facilities, and communications networks (Lampietti, Banerjee, and Branczik 2007). In summary, the country’s macroeconomic and political problems were reflected in the power sector. Power sector losses during the period of turmoil were high and unsustainable; internal sources of capital for system rehabilitation were nonexistent; and the state-owned utility, rife with debt, was unable to attract outside investment.


Following the stabilization of Georgia’s economic situation in 1995, a number of changes were introduced in the operation and regulation of the power sector. These included at first power rationing, the requirement for generators to maintain reserve stocks of fuel, and the issue of credit for rehabilitating power plants. Presidential Decree No. 437 (4 July 1996), “On Restructuring the Power Sector,” initiated the power sector reform. This decree created a body to regulate wholesale and retail tariffs. The creation of the independent regulator, the Georgian National Electricity Regulatory Commission (GNERC), was intended to signal that regulatory decisions in the sector would be adopted in a transparent manner based on the rule of law and on principles of fairness and protection of rights, balancing the interests of both investors and consumers. The same decree reorganized the vertically-integrated utility Sakenenergo into three financially-independent subsectors—generation, transmission and dispatch, and distribution—within the larger holding company of Sakenenergo. Longer-term restructuring required a legal basis and legislative measures were therefore introduced (Box 2.1). They provided for tariff restructuring and identified candidate enterprises for corporatization and eventual privatization. For distribution companies, 51% of all shares had to be offered by competitive tender.

The unbundling of Sakenenergo commenced in 1996. Generation and distribution functions were removed from Sakenenergo. Joint stock companies (JSCs) took over the generation function under a holding company called Sakenenergo Generatsia. The management of the distribution system was transferred to 66 municipal distribution companies, which were under the control of local municipalities. Transmission and dispatch activities were left under Sakenenergo (Figure 2.4).

Following the unbundling, the Ministry of Fuel and Energy of Georgia was reestablished in 1996 to oversee the power sector reforms and to address the power crisis. During the same year, the Gardabani thermal power plant was rehabilitated and the Georgian Wholesale Electricity Market was created.

An influx of foreign assistance and foreign investment aimed at assisting the economic transition, focused in part on helping to reform the power sector, with the distribution system attracting initial interest from foreign investors. In 1998, the American company AES bought 75% shares of JSC Telasi, the distribution company in Tbilisi, for $25 million. It was the first major privatization in the power sector. The privatization contract was signed on 21 December 1998 and AES Silk Road Holding B.V. (a subsidiary of AES Corporation) began operating in Telasi on 4 January 1999. In 1999, AES purchased the ninth and tenth blocks (gas generation units) of the Tbilsresi thermal power plant for $16.5 million and was awarded management rights for Khrami 1 and 2 hydropower plants for 25 years (Transparency International Georgia 2008). The privatization of Telasi and the entry of AES into the Georgian market was a major turning point in the reform process and
was followed by other privatizations; for example Kakheti Distribution was also privatized in 1999 and is now owned by a Latvian company.

AES introduced a modern metering, billing, and collection system, and dismissed corrupt cash collectors. Telasi’s collection rates went up dramatically compared to system averages and revenues for distribution services, and consumed power began to circulate within the entire power sector. The effect of AES reforms on the power system, and the improved flow of funds throughout the sector, can be seen in the following tables.

Table 2.1 shows that the average price increased and improvements under the AES resulted in increased demand and higher collection rates during 2000–2002. Table 2.2 shows the impact of the initial reforms on the revenue position of the whole sector.
### Table 2.1: Georgia—AES Telasi Collection Rates, 2000–2002

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Telasi Received Power (GWh)</td>
<td>2,790</td>
<td>2,380</td>
<td>1,200</td>
<td>-15</td>
<td>-6</td>
</tr>
<tr>
<td>Telasi Requested Power (GWh)</td>
<td>3,230</td>
<td>2,760</td>
<td>1,290</td>
<td>-14</td>
<td>-20</td>
</tr>
<tr>
<td>Ratio of Received to Requested Power (%)</td>
<td>86</td>
<td>86</td>
<td>93</td>
<td>0 percentage points</td>
<td>7 percentage points</td>
</tr>
<tr>
<td>Average Price (GEL/kWh)</td>
<td>0.093</td>
<td>0.100</td>
<td>0.124</td>
<td>8</td>
<td>24</td>
</tr>
<tr>
<td>Households Remetered (%)</td>
<td>38</td>
<td>69</td>
<td>76</td>
<td>32 percentage points</td>
<td>7 percentage points</td>
</tr>
<tr>
<td>Demand (GWh)</td>
<td>2,350</td>
<td>2,310</td>
<td>2,490</td>
<td>-2</td>
<td>24</td>
</tr>
<tr>
<td>Billings (GEL million)</td>
<td>217</td>
<td>232</td>
<td>309</td>
<td>7</td>
<td>33</td>
</tr>
<tr>
<td>Total Receipts (GEL million)</td>
<td>96</td>
<td>186</td>
<td>266</td>
<td>93</td>
<td>44</td>
</tr>
<tr>
<td>Subsidies (GEL million)</td>
<td>35</td>
<td>44</td>
<td>55</td>
<td>25</td>
<td>26</td>
</tr>
<tr>
<td>Winter Heat Assistance Program (GEL million)</td>
<td>29</td>
<td>37</td>
<td>47</td>
<td>28</td>
<td>27</td>
</tr>
<tr>
<td>Government Privileges</td>
<td>6</td>
<td>7</td>
<td>8</td>
<td>11</td>
<td>21</td>
</tr>
<tr>
<td>Government privileges (million GEL)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Payments by Customers (GEL million)</td>
<td>61</td>
<td>142</td>
<td>211</td>
<td>132</td>
<td>49</td>
</tr>
<tr>
<td>Collection Rate from Households (%)</td>
<td>44</td>
<td>80</td>
<td>86</td>
<td>36 percentage points</td>
<td>6 percentage points</td>
</tr>
</tbody>
</table>

GEL = lari (Georgian currency), GWh = gigawatt-hour, kWh = kilowatt-hour.
Notes: Table includes only Tbilisi households in the sample. Requested and received power in 2002 is only from January to June.
Source: AES Telasi, presented in Lampietti, Banerjee, and Branczik (2007).

### Table 2.2: Georgia—Power Sector Quasi Fiscal Losses, 2001–2004

<table>
<thead>
<tr>
<th></th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quantity Delivered (GWh)*</td>
<td>6,085.5</td>
<td>6,433.7</td>
<td>6,669.8</td>
<td>7,076.9</td>
</tr>
<tr>
<td>Collection Rate (%)b</td>
<td>19.7</td>
<td>35.0</td>
<td>52.4</td>
<td>48.0</td>
</tr>
<tr>
<td>Generation Cost ($ million)</td>
<td>247.7</td>
<td>263.5</td>
<td>298.6</td>
<td>357.0</td>
</tr>
<tr>
<td>Billed ($ million)</td>
<td>247.7</td>
<td>263.5</td>
<td>277.9</td>
<td>339.0</td>
</tr>
<tr>
<td>Collected ($ million)</td>
<td>48.8</td>
<td>92.2</td>
<td>145.6</td>
<td>162.7</td>
</tr>
<tr>
<td>Total Losses ($ million )</td>
<td>198.9</td>
<td>171.3</td>
<td>152.9</td>
<td>194.3</td>
</tr>
<tr>
<td>Of which: price effect ($ million )</td>
<td>0.0</td>
<td>0.0</td>
<td>20.6</td>
<td>18.0</td>
</tr>
<tr>
<td>Of which: nonpayment effect ($ million)</td>
<td>198.9</td>
<td>171.3</td>
<td>132.3</td>
<td>176.3</td>
</tr>
<tr>
<td>Total Losses (% of GDP)</td>
<td>6.2</td>
<td>5.0</td>
<td>3.8</td>
<td>3.7</td>
</tr>
</tbody>
</table>

GDP = gross domestic product, GWh = gigawatt-hour.
* Quantity produced domestically and net imports less normative losses (15 % in 2002 and 2003, 9 % in 2004 and 2005).
b United Distribution Company collection rate for 2002 is based on IMF estimates.
Source: International Monetary Fund (2005).
Transferring the distribution function to foreign companies was seen as a means of introducing modern management skills to the sector and, on the advice of the International Finance Corporation, the remaining distribution companies were merged to make them attractive to prospective foreign investors. Thus, almost all municipal distribution companies (except for Adjara, Kakheti, and those in the occupied territories) were merged to form the United Electricity Distribution Company (UEDC). In 2003, management of the UEDC was transferred to the United States Agency for International Development (USAID) contractor PA Consulting, under the USAID-funded project Georgian Energy Security Initiative. In 2007, the assets of UEDC, Adjara, and six generation companies were sold to Energo-Pro Georgia, a subsidiary of the Czech company Energo-Pro. In 2003, AES left the Georgian market, selling its shares to the company Rao-Telasi (75% owned by Inter RAOUES [a Russian electricity company] and 25% owned by the Georgian state). This meant that three key distribution companies were foreign majority-owned with the fourth one, Abkhazia Distribution, fully state-owned.

Similarly, in 2001, management of the single buyer Georgian Wholesale Electricity Market was transferred to the Spanish company Iberdrola for a period of 5 years under a management contract sponsored by the European Bank for Reconstruction and Development. In 2002, the electricity transmission company and electricity dispatch company, created after the final dissolution of Sakenergo, were merged into the Georgian State Electrosystem (GSE). In 2003, the GSE was placed under a 5-year management contract with the Irish company, Electricity Supply Board Ireland. The 2003 transfer of GSE management to the Electricity Supply Board Ireland was sponsored by the World Bank and KfW Entwicklungsbank, the German development bank.

These institutional changes helped to reduce corruption and improve poor financial and technical performance by introducing communal and wholesale meters, instituting new information technology and billing systems, enforcing internal controls, and introducing the expertise of international companies in running the sector.

### 2.3. Phase 2 (2004–Present): New Wave of Reforms

The second phase of general economic reforms occurred after the Rose Revolution of 2003. Following parliamentary elections in 2004, general reform measures were instituted throughout the economy. In 2005, the government injected several hundred million United States dollars into the power sector, to rehabilitate state-owned generation, distribution, and transmission assets. Improved financing by donors and the state-provided major investment in transmission made possible a major transformation of the GSE (Figure 2.5). This rehabilitation resulted in improved reliability of the transmission network, and technical losses and blackouts decreased significantly.

In December 2005, amendments to the Law on Electricity and Natural Gas altered the responsibility for power sector regulation by transferring approval of market rules from the regulator (GNERC) to the Ministry of Energy. The Ministry of Energy was also authorized to issue technical rules, approve power and natural gas balances, and make decisions about deregulation and partial deregulation.

**Figure 2.5: Georgia—Investing in Transmission**

<table>
<thead>
<tr>
<th>Year</th>
<th>Loan Funds</th>
<th>GSE Funds</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td>1.4 GEL</td>
<td>1.8 GEL</td>
</tr>
<tr>
<td>2005</td>
<td>8.2 GEL</td>
<td>14.2 GEL</td>
</tr>
<tr>
<td>2006</td>
<td>4.3 GEL</td>
<td>8.6 GEL</td>
</tr>
<tr>
<td>2007</td>
<td>15.3 GEL</td>
<td>11.6 GEL</td>
</tr>
<tr>
<td>2008</td>
<td>23.3 GEL</td>
<td>29.5 GEL</td>
</tr>
<tr>
<td>2009</td>
<td>22.3 GEL</td>
<td>23.2 GEL</td>
</tr>
<tr>
<td>2010</td>
<td>28.4 GEL</td>
<td>3.7 GEL</td>
</tr>
<tr>
<td>2011</td>
<td>20.1 GEL</td>
<td>70.5 GEL</td>
</tr>
</tbody>
</table>

GNERC was required to comply with the normative instructions of the Ministry of Energy. The GNERC was isolated and perhaps further weakened by being relocated to the city of Kutaisi, about 200 kilometers west of Tbilisi. Its new responsibilities included approving supply and consumption rules; approving wheeling charges; and fees of the Electricity System Commercial Operator (ESCO), for guaranteed capacity and for network connections.

On 9 June 2006, the Parliament approved the Parliament Resolution “On Main Directions of State Policy in the Georgian Energy Sector” focusing on energy efficiency and sustainability, efficient pricing, and bilateral and regional cooperation, among other things. The Resolution envisaged full opening of the power market and wholesale competition by 2017, and ultimately the full satisfaction of the country’s electricity demand from domestic hydro resources through a gradual substitution, first of imports and then of thermal generation.

On 1 September 2006, the Georgian Wholesale Electricity Market with its single-buyer model was replaced by the ESCO. Under the ESCO, generators, distribution companies, direct customers, and exporters are allowed to enter into direct contracts, while the ESCO buys and sells balancing power and reserve capacity. In recent years, about 85% of sales have been made under direct contracts. In April 2008, negotiating power purchase agreements for new hydropower plants (in conjunction with the government) was added to the ESCO’s functions. Box 2.2 enumerates the current responsibilities of key institutions in the sector, defined and modified over the reform period.

Also in 2006, most generating companies were entitled to trade power at market price, while tariffs for some were capped. The restructured tariff scheme also required introducing differentiated consumer tariffs. Domestic tariffs rose to cost-recovery levels and wheeling charges were introduced. Figure 2.6 shows the evolution of consumer tariffs during the reform period.

The tariff reform, however, is incomplete. Tariffs have not been updated regularly to reflect costs or other changes; in fact, tariffs have been fixed in nominal terms during 2006–2012 for residential consumers in Tbilisi and in the regions, and for industrial consumers in Tbilisi. In 2013, tariffs for residential units consuming up to 301 kWh were reduced by more than 20%. And the costs of power purchases are not transparent, so that it is not possible to judge how far tariffs reflect costs.

**Box 2.2: Georgia—Key institutions**

The **Ministry of Energy** is responsible for overall energy policy. In principle, its influence is primarily confined to policy-related and strategic matters. In practice, however, the Ministry of Energy is actively involved in both the operation and de facto regulation of the sector by virtue of its authority to approve power sector electricity balances, supervise state-owned enterprises, and approve market rules and other regulations.

The **Georgian National Energy and Water Supply Regulatory Commission** is in principle the independent legal body responsible for the day-to-day regulation of the power sector. It has authority to grant and regulate licenses (for generation, transmission, dispatch, and distribution), and to set and regulate tariffs, but only in accord with Ministry of Energy directives. It also has power to resolve disputes between licensees and consumers. It also regulates natural gas and water sectors.

The **Electricity System Commercial Operator** buys and sells balancing power and reserve capacity to balance supply and demand. It may also enter into power purchase agreements with the new hydropower plants and is a signatory to relevant government memoranda.

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*The commission was formerly known as the Georgian National Energy Regulatory Commission. In 1996 and 2007, regulation of natural gas and water supplies were added to its functions. Its name was later changed to Georgian National Energy and Water Supply Regulatory Commission, while retaining GNERC as its acronym.

Sources: Compiled based on information from the Charter of the Ministry of Energy 2006; Law on Electricity and Natural Gas 1999; 2007 Amendments to the Law on Electricity and Natural Gas; and ESCO, Legislation, Legislative Acts.*
2.4. Current Structure of the Sector

2.4.1. Generation

Georgia has an installed generating capacity of about 3,339 megawatts (MW) comprising a mix of hydro and thermal power plants (Table 2.3). The country has more than 20 medium and large, and more than 40 small (below 13 MW) hydro generation plants, for a total installed capacity of about 2,657 MW, and thermal power plants (mostly gas fired) with a total installed capacity of 682 MW. Hydropower is dominated by the Enguri power plant and its downstream companion Vardnili. Together they account for about 45% of total installed capacity and produce 40%–50% of total hydro generation. These plants are on occupied territory and hence are not under full control of Georgian authorities. Installed capacity is estimated to reach 4,000 MW by 2022 (Ministry of Energy of Georgia 2014).

Table 2.4 shows the installed capacity and annual generation of each power plant operating in 2013,
together with its year of commissioning. Figure 2.7 illustrates the changing balance between hydro and thermal sources.

In the post-2005 reform period, electricity capacity has largely been expanded through refurbishing generating plants. Only three projects increased installed capacity: the construction of the 24-MW hydropower plant (Khadorihesi) and the 110-MW thermal power plant (Energy Invest, currently called G-power), and 4-MW increase of Khrami 2’s installed capacity. The largest share of power generation (75%–90%, depending on the year) comes from hydropower stations. The two largest generating stations (Enguri and Vardnilihesi) are state-owned; 15 others belong to Enrgo-Pro Georgia and two are owned by the Russian company Inter RAQUES, with the rest being under private ownership. Inter RAQUES also owns the thermal power station Mtkvari Energy. Other companies owning major generation plants are the Georgian Industrial Group; Georgian Water and Power; and Georgian Manganese, which also owns major power-consuming enterprises.

### Table 2.3: Georgia—Aggregate Installed Capacity, 2013

<table>
<thead>
<tr>
<th>Plant</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydropower plant</td>
<td>2,657.1</td>
</tr>
<tr>
<td>Thermal power plant</td>
<td>682.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,339.1</strong></td>
</tr>
</tbody>
</table>

GWh = gigawatt-hour, MW = megawatt.

### Table 2.4: Georgia—Operating Power Plants, 2013

<table>
<thead>
<tr>
<th>No</th>
<th>Power Plant</th>
<th>Start date</th>
<th>Type</th>
<th>Installed Capacity (MW)</th>
<th>Generation (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Enguri</td>
<td>1978</td>
<td>Hydro</td>
<td>1,300.0</td>
<td>3,605.13</td>
</tr>
<tr>
<td>2</td>
<td>Mtkvari</td>
<td>1990–1995</td>
<td>Thermal</td>
<td>300.0</td>
<td>899.35</td>
</tr>
<tr>
<td>3</td>
<td>Vartsikhehesi</td>
<td>1976</td>
<td>Hydro</td>
<td>184.0</td>
<td>864.35</td>
</tr>
<tr>
<td>4</td>
<td>Tbilsresi</td>
<td>1965</td>
<td>Thermal</td>
<td>272.0</td>
<td>861.53</td>
</tr>
<tr>
<td>5</td>
<td>Vardnilihesi</td>
<td>1971</td>
<td>Hydro</td>
<td>220.0</td>
<td>667.20</td>
</tr>
<tr>
<td>6</td>
<td>Lajanurhesi</td>
<td>1960</td>
<td>Hydro</td>
<td>112.5</td>
<td>450.42</td>
</tr>
<tr>
<td>7</td>
<td>Zhinvalhesi</td>
<td>1985</td>
<td>Hydro</td>
<td>130.0</td>
<td>394.08</td>
</tr>
<tr>
<td>8</td>
<td>Gumathesi</td>
<td>1956</td>
<td>Hydro</td>
<td>68.8</td>
<td>345.34</td>
</tr>
<tr>
<td>9</td>
<td>Rionhesi</td>
<td>1933</td>
<td>Hydro</td>
<td>48.0</td>
<td>308.35</td>
</tr>
<tr>
<td>10</td>
<td>Khrami II</td>
<td>1963</td>
<td>Hydro</td>
<td>114.4</td>
<td>299.24</td>
</tr>
<tr>
<td>11</td>
<td>Khrami-I</td>
<td>1947</td>
<td>Hydro</td>
<td>112.8</td>
<td>186.71</td>
</tr>
<tr>
<td>12</td>
<td>Zahesi</td>
<td>1927</td>
<td>Hydro</td>
<td>36.8</td>
<td>169.21</td>
</tr>
<tr>
<td>13</td>
<td>Khadorihesi</td>
<td>2005–2006</td>
<td>Hydro</td>
<td>24.0</td>
<td>146.14</td>
</tr>
<tr>
<td>14</td>
<td>Dzevrulhesi</td>
<td>1956</td>
<td>Hydro</td>
<td>80.0</td>
<td>124.72</td>
</tr>
<tr>
<td>15</td>
<td>Shaorihesi</td>
<td>1948–1955</td>
<td>Hydro</td>
<td>38.4</td>
<td>107.98</td>
</tr>
<tr>
<td>16</td>
<td>Chitakhvhesi</td>
<td>1949</td>
<td>Hydro</td>
<td>21.0</td>
<td>91.99</td>
</tr>
<tr>
<td>17</td>
<td>Ortchalahesi</td>
<td>1961</td>
<td>Hydro</td>
<td>18.0</td>
<td>83.27</td>
</tr>
<tr>
<td>18</td>
<td>Atshesi</td>
<td>1941</td>
<td>Hydro</td>
<td>16.0</td>
<td>80.13</td>
</tr>
<tr>
<td>19</td>
<td>G-power</td>
<td>2005–2006</td>
<td>Thermal</td>
<td>110.0</td>
<td>26.84</td>
</tr>
<tr>
<td>20</td>
<td>Satskhenishesi</td>
<td>1952</td>
<td>Hydro</td>
<td>14.0</td>
<td>17.93</td>
</tr>
<tr>
<td>21</td>
<td>Small Hydropower plants (&lt;13 MW)</td>
<td>1956</td>
<td>Hydro</td>
<td>118.4</td>
<td>328.84</td>
</tr>
</tbody>
</table>

GWh = gigawatt-hour, MW = megawatt.
2.4.2. Transmission

The transmission grid consists of a network of 6-, 10-, 35-, 110-, 220-, 330-, 400- and 500-kilovolt (kV) lines. It covers almost all of Georgia, except for some remote mountain villages, and is interconnected with Armenia, Azerbaijan, the Russian Federation (through Abkhazia), and Turkey. The major transmission companies are Joint Stock Company (JSC) Sakrusenergo and GSE. JSC Sakrusenergo is owned 50% by the government and 50% by Inter RAOUES. JSC Sakrusenergo operates very high-voltage lines (330 kV and 500 kV) and its main function is the transmission of electricity through interconnected lines with neighboring countries (except Armenia). The GSE owns 35-kV lines (in the Kakheti Region), 110-kV and 220-kV lines, and substations. The GSE’s main activities are domestic electricity transmission through the high-voltage network (35, 110, and 220 kV), and electricity dispatch. All power transmitted within Georgia through JSC Sakrusenergo goes through the GSE network. Two other companies will soon be involved with transmission. Energotrans Ltd, a subsidiary of GSE, owns the Black Sea Transmission Line, which connects Georgia and Turkey. Energo-Pro has also constructed a transmission line to Turkey, which is expected to be commissioned in the fourth quarter of 2014.

2.4.3. Distribution

The distribution network consists of 6-, 10-, 35-, 110-kV lines and substations, supplying electricity to about 1.45 million consumers. Power is supplied to small residential and commercial consumers at 220 and 380 volts (V) and to large consumers at a higher voltage. The three distribution companies are JSC Telasi; supplying power to about 493,000 consumers in Tbilisi; JSC Energo-Pro Georgia, serving about 952,000 customers in the regions; and JSC Kakheti Energy Distribution, with about 139,000 customers in Kakheti Region. Table 2.5 summarizes the networks and coverage of the three distribution companies.

The three companies currently serve the vast majority of the country, except for the occupied territories and a small population in remote mountain villages. All three distribution companies, also buy electricity and sell it to their customers.

JSC Energo-Pro Georgia, which is owned by a Czech company, is the largest distribution company, with high-, medium-, and low-voltage networks throughout most of Georgia (except in Tbilisi and the Kakheti Region). JSC Energo-Pro bought the

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*See www.energo-pro.ge*
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assets of UEDC, of the Achara distribution company, and of 6 medium sized hydropower plants, and now owns 15 hydroelectric power stations. JSC Energo-Pro’s total installed capacity is more than 469 MW, about 18% of the country’s hydropower capacity. As noted above, JSC Energo-Pro is developing its own transmission line to Turkey. JSC Telasi is the second largest distribution company in Georgia, and is owned 75% by the Russian company Inter RAOUES. It owns high-, medium-, and low-voltage networks in Tbilisi and its surrounding areas,9 supplying about 2 billion kWh per year to its customers. Under a memorandum of understanding signed with the government, Telasi has an assured long-term tariff until 2026. JSC Kakheti Energy Distribution, owned by a Latvian company, is a distribution company operating in the Kakheti Region, with medium- and low-voltage networks, providing 200 gigawatt-hours of electric energy annually to its consumers (GNERC 2013 and 2014).

2.4.4. External Power Trade and Supply Vulnerabilities

Foreign trade remains important to the sector because electricity has to be imported to balance the seasonal fluctuations in hydropower generation, and natural gas imports are needed to fuel thermal generation. Table 2.6 and Figure 2.7 show the evolution of power generation, demand, imports, and exports during 1990–2013.10 Import vulnerability is a key aspect of energy and electricity supply security. Although electricity trade per se is not a threat to supply security, having a dominant or single supplier can pose a security risk. As Georgia has already experienced, without alternative suppliers of sufficient capacity, political concerns or accidents can lead to disruptions in deliveries and to reductions in available power.

The bulk of electricity trade is with the Russian Federation, comprising imports in winter months to meet domestic demand and exports in summer when Georgia has excess hydro output. Trade with Azerbaijan follows a similar pattern but on a smaller scale. Trade with Armenia and Turkey comprises exports during summer months. The power sector trade balance can change from one year to the next with; for example, Georgia shifted from a net electricity exporter in 2011 to a net importer in 2012 and 2013 (Figure 2.9).

As with power imports, gas imports are governed largely by the seasonality of the hydro cycle, and tend to be highest in the winter months. Given that hydropower generation supply peaks in summer when demand is low and drops in winter when demand is high, even in years when Georgia is a net exporter of electricity, it will need thermal power and hence gas imports. This pattern is likely to continue until and if, as planned, the composition of generating

Source: GNERC (2014).

<table>
<thead>
<tr>
<th>Distribution Company</th>
<th>Ownership</th>
<th>Networks</th>
<th>Service Area</th>
<th>Number of Customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>JSC Energo-Pro Georgia</td>
<td>Czech Company</td>
<td>high (35-110 kV), medium (6-10 kV), low (0.4 kV)</td>
<td>Entire Georgia except Tbilisi and Kakheti</td>
<td>952,228</td>
</tr>
<tr>
<td>JSC Telasi</td>
<td>75% owned by Inter RAOUES (Russian company)</td>
<td>high (35-110 kV), medium (6-10 kV), low (0.4 kV)</td>
<td>Tbilisi</td>
<td>492,813</td>
</tr>
<tr>
<td>JSC Kakheti</td>
<td>Latvian Company</td>
<td>medium (6-10 kV), low (0.4 kV)</td>
<td>Kakheti</td>
<td>138,872</td>
</tr>
</tbody>
</table>

$kV = kilovolt.$

See www.telasi.ge

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10 Lali Gogishvili, a former director of the Energy Department of GNERC, provided imports data for years 1995 to 2006.
Table 2.6: Georgia—Electricity Generation, Demand, and Import and Export, 1990–2013

<table>
<thead>
<tr>
<th>Year</th>
<th>Demand for Electricity a (million kWh)</th>
<th>Power Generationb (million kWh)</th>
<th>Thermal Power Plants</th>
<th>Hydropower Plants</th>
<th>Import</th>
<th>Export</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>17,443</td>
<td>14,240</td>
<td>6,645</td>
<td>7,595</td>
<td>3,203</td>
<td>0</td>
</tr>
<tr>
<td>1991</td>
<td>15,610</td>
<td>13,369</td>
<td>6,322</td>
<td>7,047</td>
<td>2,241</td>
<td>0</td>
</tr>
<tr>
<td>1992</td>
<td>12,500</td>
<td>11,501</td>
<td>5,003</td>
<td>6,498</td>
<td>999</td>
<td>0</td>
</tr>
<tr>
<td>1993</td>
<td>10,836</td>
<td>10,122</td>
<td>3,092</td>
<td>7,030</td>
<td>714</td>
<td>0</td>
</tr>
<tr>
<td>1994</td>
<td>7,952</td>
<td>7,030</td>
<td>2,119</td>
<td>4,911</td>
<td>922</td>
<td>0</td>
</tr>
<tr>
<td>1995</td>
<td>7,826</td>
<td>7,074</td>
<td>866</td>
<td>6,208</td>
<td>754</td>
<td>0</td>
</tr>
<tr>
<td>1996</td>
<td>7,314</td>
<td>7,231</td>
<td>1,186</td>
<td>6,045</td>
<td>410</td>
<td>-126</td>
</tr>
<tr>
<td>1997</td>
<td>7,303</td>
<td>7,121</td>
<td>1,128</td>
<td>5,993</td>
<td>705</td>
<td>-465</td>
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<tr>
<td>1998</td>
<td>8,302</td>
<td>8,088</td>
<td>1,698</td>
<td>6,390</td>
<td>810</td>
<td>-796</td>
</tr>
<tr>
<td>1999</td>
<td>8,368</td>
<td>8,118</td>
<td>1,634</td>
<td>6,485</td>
<td>434</td>
<td>-384</td>
</tr>
<tr>
<td>2000</td>
<td>7,875</td>
<td>7,480</td>
<td>1,538</td>
<td>5,942</td>
<td>568</td>
<td>-198</td>
</tr>
<tr>
<td>2001</td>
<td>7,811</td>
<td>6,503</td>
<td>965</td>
<td>5,538</td>
<td>447</td>
<td>-527</td>
</tr>
<tr>
<td>2002</td>
<td>7,718</td>
<td>7,234</td>
<td>513</td>
<td>6,721</td>
<td>635</td>
<td>-158</td>
</tr>
<tr>
<td>2003</td>
<td>7,978</td>
<td>7,144</td>
<td>635</td>
<td>6,509</td>
<td>989</td>
<td>-159</td>
</tr>
<tr>
<td>2004</td>
<td>8,110</td>
<td>6,902</td>
<td>874</td>
<td>6,028</td>
<td>1,208</td>
<td>0</td>
</tr>
<tr>
<td>2005</td>
<td>8,145</td>
<td>6,868</td>
<td>1,030</td>
<td>5,838</td>
<td>1,399</td>
<td>-122</td>
</tr>
<tr>
<td>2006</td>
<td>8,273</td>
<td>7,621</td>
<td>2,225</td>
<td>5,396</td>
<td>778</td>
<td>-140</td>
</tr>
<tr>
<td>2007</td>
<td>7,815</td>
<td>8,346</td>
<td>1,515</td>
<td>6,831</td>
<td>433</td>
<td>-625</td>
</tr>
<tr>
<td>2008</td>
<td>8,075</td>
<td>8,450</td>
<td>1,281</td>
<td>7,169</td>
<td>649</td>
<td>-680</td>
</tr>
<tr>
<td>2009</td>
<td>7,642</td>
<td>8,408</td>
<td>991</td>
<td>7,417</td>
<td>255</td>
<td>-749</td>
</tr>
<tr>
<td>2010</td>
<td>8,441</td>
<td>10,058</td>
<td>683</td>
<td>9,375</td>
<td>222</td>
<td>-1,524</td>
</tr>
<tr>
<td>2011</td>
<td>9,257</td>
<td>10,105</td>
<td>2,212</td>
<td>7,892</td>
<td>471</td>
<td>-931</td>
</tr>
<tr>
<td>2012</td>
<td>9,379</td>
<td>9,695</td>
<td>2,472</td>
<td>7,223</td>
<td>615</td>
<td>-528</td>
</tr>
<tr>
<td>2013</td>
<td>9,690</td>
<td>10,059</td>
<td>1,788</td>
<td>8,271</td>
<td>484</td>
<td>-450</td>
</tr>
</tbody>
</table>

kWh = kilowatt-hour.

a Electricity demand refers to the amount of electricity supplied to consumers. b Generation figures include generating plant use and plant losses.


Figure 2.8: Georgia—Generation, Demand, and Import and Export, 1990–2013 (billion kWh)

kWh = kilowatt hour.

Assessment of Power Sector Reforms in Asia

capacity shifts totally to hydro. Until 2007, 100% of natural gas for thermal power was imported from the Russia Federation or Turkmenistan through Russian territory. In January 2006, both natural gas pipelines connecting the two countries were damaged and for several days Georgia was left without power. This crisis highlighted an import security risk and prompted a concern to diversify supplies. Currently, most natural gas comes from Azerbaijan.

Figure 2.10 gives a simple measure of electricity import dependence and supply vulnerability. The latter is defined as the sum of net imports plus thermal generation (which relies on imported fuel) divided by total electricity consumption. From 1990 to 2006, Georgia in most years was a net importer. From 2007 to 2011, Georgia became a net exporter—its import dependence fell from 35% in 2006 to −15.4% as a net exporter in 2010. During 2012–2013, Georgia was back to being a net importer. Its supply vulnerability indicator has followed a similar trend with a rising share of imports and import-dependent generation in total consumption in the last few years.

2.5. Limitations of Reform

A major focus of the reforms in Georgia has been the restructuring of the power sector. The sector has been unbundled and largely privatized and a wholesale market has been created. The participants in wholesale trade are the generation companies, the distribution companies, and qualified customers. Wholesale trade is conducted either by the ESCO

Figure 2.9: Georgia—Electricity Trade, 2012–2013 (million kWh)

kWh = kilowatt-hour.

Figure 2.10: Georgia—Dependence of Electricity Demand on Gas and Power Imports (%)

Note: For electricity supply vulnerability, the sum of imported electricity and of thermal power plant generation is divided by the amount of total demand. Thermal power plant generation is used in this calculation because thermal power plants use natural gas, which is almost entirely imported from other countries.
or by direct contracts among dispatch licensees, sellers, and buyers, under standard contract terms provided by the ESCO. The ESCO trades about 15% of wholesale power, and is responsible for balancing electricity trade. However, the government still directly or indirectly retains an important financial interest in the power sector. Figure 2.11 shows the schema of the wholesale market.

The sector retains some noncompetitive structural features that can limit the potential benefits of competition. Most important, although great progress has been made in the efficiency of system pricing and in developing commercial viability in the sector, transparency in pricing and independent regulatory competence are still lacking. Generation, transmission, and distribution companies often have the same owners, or form part of the same vertically integrated company. Because bilateral power purchase agreements are the main form of electricity trade, one would expect buyers to prefer to procure electricity from their own generation sources. Vertical reintegration can thus enhance corporate profitability, but may also nullify the competitive potential expected from the mainly horizontal break-up of the public sector utility. Figure 2.12 shows the power system as divided into several, vertically re-integrated segments (Energo–
Pro [orange], Inter RAO UES [blue], Georgian State [red], Abkhazia [purple], and other generator and/or consumer companies [green]). For example, Inter RAO UES holds shares in transmission, distribution, and generation companies, while Energo-Pro holds assets of distribution and generation companies and is building a transmission line.

Nonetheless, the electricity sector’s economic efficiency and viability has been successfully improved. In contrast to the situation before reforms, the power sector operates in a business climate largely conducive to efficiency both in terms of service and financial viability. Bankruptcy has given way to profitability; power shortages have been replaced by adequate or surplus generation, with the surplus exported profitably; investment has been made available to rehabilitate old infrastructure and build new plants; and the interdependent state-owned structure of earlier days has been unbundled into generation, transmission, and distribution companies and restructured as a market-based, largely privatized or privately managed commercial industry. A key factor in these gains has been the privatization of management in the sector, as evidenced first by the transformation in profitability resulting from the management of JSC Telasi by AES.

In terms of governance and regulatory reform, Georgia has in place legal and regulatory requirements for transparent, reliable, and competent regulation. The legislative and executive measures that initiated the reform process established the principles and conditions for a more competitive and effectively regulated sector. However, subsequent amendments in some cases have altered the original tenor of the authorizations designed to implement reforms and regulation. Perhaps because of political concerns, many regulatory obligations have been compromised and their implementation delayed, while some have been ignored and some contravened by political fiat. The regulatory body in theory is independent, but until recently some of its activities, including

Figure 2.12: Georgia—Rebundled Structure of the Power Sector

Source: Kavtaradze and Margvelashvili (2012).
the setting of tariffs according to preapproved tariff methodologies, were subordinated to Ministry of Energy decisions or other government actions, although the current government is committed to a genuinely independent regulatory system. Georgia has begun negotiations for its accession to the European Energy Community. If and when accession is agreed, the country will be obliged to ensure that “energy markets are operated with a view to achieving competitive, secure, and environmentally sustainable conditions and shall not discriminate between enterprises as regards rights or obligations”; and that the “methodology underlying the calculation of the regulated price of electricity and gas is published prior to the entry into force of the regulated price.”

To date, Georgia has no legal or regulatory provisions to promote energy efficiency.

Transparency is still lacking throughout the regulation and administration of the sector. Power purchase agreements, tariff construction, and the pricing of power plant construction and contracting are typically negotiated privately by government officials without external scrutiny, and hence without accountability. The situation has improved with the approval of Government Decree No. 214, of 21 August 2013, “Approval of the Rules for Expression of Interests for Feasibility Study of Construction, Construction, Ownership, and Operation of Power Plants,” which set transparent criteria for all interested parties, although how this will be applied in practice is not yet clear.

Lack of transparency in tariff setting is a key weakness. A number of transactions are not covered by promulgated tariffs and the costs behind them are not transparent. Information with regard to many supply costs or actual charges for electricity and related services is not available. It is highly desirable for all charges not only to be transparent, but also to be transparently arrived at, whether promulgated or negotiated. Distribution and consumer tariffs have largely been agreed with the government in nontransparent negotiations. With the change of government in October 2012, consumer tariffs for households were reduced, but again as a result of nontransparent negotiations between the government and investors, with little or no involvement of the regulator, which formally approved the new tariffs in April 2013. Without transparency, it is impossible to know whether tariffs in fact reflect costs.

Existing regulations require that new generating plants sell (in the winter months) 20% of their annual output in Georgia whether to the ESCO at a renegotiated price or to another buyer at a market price. In other months, generating plants are free to export power. However, because they can only commit to exporting power for 9 months of the year, they are in a weak position to negotiate power export agreements, especially with Turkey. This makes year-round revenues more uncertain and the construction of new plants less attractive.

One remedy proposed to resolve this problem is the introduction of feed-in tariffs for new power plants. However, such tariffs constitute subsidies to the new plants, and as imposed in other countries have seriously skewed both dispatch and system costs.

A long-term system plan could help to attract investment for new projects and would complement the institutional and legislative changes introduced by the reform program. Progress is being made to develop such a plan. Currently, the GSE is preparing a 10-year network development plan along with the Ministry of Energy of Georgia, and in accord with the Georgian Transmission Grid Code adopted in April 2014. The new 10-year plan will cover generation and transmission projections and demand forecasts. The Ministry of Energy is also working on a new energy strategy (to the year 2020). Completion of the plan and strategy will be an important contribution to successful reform.
3. POWER SECTOR REFORM IN SRI LANKA

From the late 1960s, economic development in Sri Lanka was held back by a highly disruptive and costly civil war that only ended in 2009. The war greatly affected in particular the Northern and Eastern provinces, which have about two-thirds of the country’s coastal and maritime resources and one-third of the fertile land. Despite the disruption, economic growth since 1990 has been relatively high and accelerated in the initial postwar period in 2010 and 2011. Industries and services such as textiles, clothing, telecommunication, food processing, and finance developed rapidly in the early 1990s and gross domestic product grew at an average annual rate of 5.5% from 1990 to 2013 (Figure 3.1).

Economic growth has created a strong increase in demand for electricity. Electricity consumption per capita in Sri Lanka, estimated at 140 kilowatt-hours in 1990, more than tripled by 2013, to 515 kilowatt-hours. Because of delays with implementing some planned medium-scale hydropower projects, coupled with limited potential for further large hydropower development and the shortages created during periods of below-average rainfall, the rapid growth in demand required an increase in oil-fired thermal generation to supplement existing hydro sources. The increased generation came from IPPs fueled by imported oil. These plants were first introduced in 1996 and by 2013 accounted for almost

Figure 3.1: Sri Lanka—Real GDP Growth, 1990–2013 (%)
17% of total generation (PUCSL 2013). Thus, during the last 2 decades, the electricity generating system has changed from a predominantly hydroelectric system to a mixed hydro–thermal system (Figure 3.2). Installed generation capacity has always been above peak demand (Figure 3.3), but before the independent power producers (IPPs) were introduced to provide additional supply, the high dependence on hydropower meant that periods of below-average rainfall created temporary shortages of available capacity, with consequent power shortages and load shedding.

3.1. Background to Reform

Since the end of the civil war, the government has made serious efforts to repair war-related damage under programs such as the Nagenahira Navodaya (Eastern Revival) and Uthuru Wasantham (Northern Spring). Electrification rates have improved significantly. In 1990, an estimated 71% of households were without grid access; by 2003, the figure was 32% and by 2013 it had been reduced very substantially, to 4%.

Figure 3.2: Sri Lanka—Changing Fuel Mix in Electricity Generation (%)

![Figure 3.2: Sri Lanka—Changing Fuel Mix in Electricity Generation (%)](source: Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance (accessed 20 October 2014).

Figure 3.3: Sri Lanka—Installed Generation Capacity and Peak Demand (MW)

![Figure 3.3: Sri Lanka—Installed Generation Capacity and Peak Demand (MW)](source: Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance (accessed 20 October 2014).
The power sector operated initially under a government department, and, from 1969, under a public sector utility—the Ceylon Electricity Board (CEB)—which carried out all the functions of electricity generation, transmission, distribution, and retail supply. Thus, in the prereform period, the CEB operated as a vertically integrated monopoly regulated by the Ministry of Power and Energy. There was no competition at any level, either at generation or at retail level.

Reforms in Sri Lanka have been driven predominantly by inefficiency in delivery and financial problems, and the worldwide trend of reforming power sectors into competitive markets. Transmission and distribution losses were high by historical standards during the early to mid-2000s. The perceived structural and managerial weaknesses and operational inefficiency within the monolithic power utility—the CEB—were a key major driver for reform.

The need to restructure was identified as at least a partial solution to numerous problems the power sector faced, including severe financial difficulties created by mismatches in the cost and price of electricity and administrative inefficiencies largely due to politicization of the sector. The CEB has reported losses since 1999.


In 1983, the state-owned distribution company Lanka Electricity Company (LECO) was established to distribute power in designated areas previously served by local authorities and municipal councils. Private sector participation in generation started in 1996 with the involvement of IPPs and small power producers (SPPs).

Between 1995 and 2001, several studies and stakeholder consultations were conducted to search for the best model for further reform of the sector. In 2000, the CEB was internally unbundled into generation, transmission, and four distribution divisions through an administrative decision, but without legally or financially separating them from the CEB. The legal basis for reform was initiated in 2002 with the Electricity Reform Act No. 28.14 The Public Utilities Commission Act No. 35 of 2002 was enacted in December 2002, establishing the Public Utilities Commission of Sri Lanka (PUCSL) as the power sector regulator as of July 2003.15 However, for the PUCSL to exercise its assigned powers over the sector, the Electricity Reform Act had to be made fully operational through a ministerial order16

Table 3.1: Sri Lanka—Key Reform Milestones

<table>
<thead>
<tr>
<th>Year</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>1983</td>
<td>Establishment of the Lanka Electricity Company (LECO)</td>
</tr>
<tr>
<td>1990</td>
<td>Completion of transfer of all local authority (municipal and city council networks) to either the LECO or the Ceylon Electricity Board</td>
</tr>
<tr>
<td>1996</td>
<td>First independent power producer commissioned</td>
</tr>
<tr>
<td>1997</td>
<td>First small power producer commissioned</td>
</tr>
<tr>
<td>2002</td>
<td>Electricity Reform Act approved by Parliament (but not implemented)</td>
</tr>
<tr>
<td>2003</td>
<td>Public Utilities Commission of Sri Lanka established to regulate the electricity industry</td>
</tr>
<tr>
<td>2009</td>
<td>10th independent power producer commissioned</td>
</tr>
<tr>
<td>2010</td>
<td>Licenses issued to 6 business entities within the Ceylon Electricity Board, and to the LECO under the new Act</td>
</tr>
<tr>
<td>2011</td>
<td>New tariff methodology finalized, tariff filing conducted, and the 1st public hearing held</td>
</tr>
<tr>
<td>2013</td>
<td>Second public hearing on tariffs held</td>
</tr>
</tbody>
</table>

Source: Authors.

14 The act was not implemented and was repealed in 2009.
15 The PUCSL functions as a general regulator of public utilities in the energy and water sectors.
16 Certain broad powers embedded in the PUCSL were already available for the PUCSL, such as advising the government on policies.
that was not issued owing to political opposition, including opposition from CEB staff. A change of government in 2004 was instrumental in putting on hold the implementation of the reform plan. In 2005, the government submitted a new electricity bill to parliament, which the Parliament took 3 years to approve. Table 3.1 gives the timeline for reform initiatives. Box 3.1 describes the key institutions in the sector.

**3.3. Moving Forward with Reform: From the Electricity Act of 2009, and On**

In February 2008, the new electricity reform bill was presented to Parliament. After several rounds of discussion and significant amendments the bill was

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**Box 3.1: Sri Lanka—Key Institutions of the Electricity Sector**

**The Ministry of Power and Energy** is mandated to formulate and implement policies, programs, and projects pertaining to power and energy. It is responsible for monitoring, planning, and developing electricity facilities, including hydro, thermal, mini hydro, coal, and wind power in the country.a

**The Ceylon Electricity Board (CEB)** is a state-owned corporation established on 1 November 1969 under the Ceylon Electricity Board Act No. 17, 1969. The CEB is engaged in power generation (1 license for 23 power plants), transmission (1 license), and distribution (4 licenses, servicing about 4.5 million customers across its four distribution regions) and in revenue collection. The license for the CEB Generation Division covers about 66% of the installed capacity on the grid, with the rest held by the private sector.b

**The Lanka Electricity Company (LECO)** is a state-owned distribution company formed in 1983; it started operating in June 1984. The LECO purchases bulk power from the CEB and distributes it to consumers in the western and coastal belt townships between Negombo and Galle. The LECO operates under the Sri Lanka Companies Act, and has the CEB and the Ministry of Finance as major shareholders; other shareholders are also state entities.c

**Independent power producers**, as classified in Sri Lanka, are private power plants engaged in thermal generation (diesel engine and combined cycle oil-fired plants). By the end of 2012, 12 independent power producers were operating.

**Small power producers** are independent private power plants that generate electricity from nonconventional renewable sources—hydro, combined heat and power, solar power, biomass, and wind. More than 130 small power producers are operating.

**The Public Utilities Commission of Sri Lanka (PUCSL)** is structured as a multi-sector regulator, and is currently mandated to act as the economic, technical, and safety regulator for the electricity industry, as well as for the petroleum and water industries, under the purview of Public Utilities Commission Act No. 35 enacted in December 2002. The PUCSL was established in July 2003. In 2009, through the passage of Electricity Act No. 20, the PUCSL was empowered to regulate the generation, transmission, distribution, supply, and use of electricity. The PUCSL is answerable to the Parliament.d

**The Sri Lanka Sustainable Energy Authority** was established in October 2007 through the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007, with a mandate to assist in developing the national policy on energy; to implement policy for renewable energy, and for energy efficiency and conservation and to promote development of renewable energy projects through private investment; and to conduct research on the development of indigenous energy resources. The Authority currently functions under the Ministry of Environment and Natural Resources.e

Sources: Compiled from

a Ministry of Power and Energy of Sri Lanka’s website (accessed May 2012).
b CEB. What We Do (accessed 21 May 2012).
e ADB (2011).
approved as the Electricity Act of 2009. This allowed the PUCSL to operate as the power sector regulator. However, the bill introduced less restructuring of the CEB than had been proposed originally in the 2002 Electricity Reform Act. A single-buyer model was introduced, with the CEB transmission entity as the single buyer, but the business units or divisions within the vertically integrated CEB were not made separate entities with an independent ownership structure and management. Thus, the CEB now holds

- one generation license (for about 66% of all generating capacity in the grid);
- one transmission license (covering 100% of transmission and 100% of bulk supply in accordance with the single-buyer model); and
- four distribution licenses (in total accounting for about 90% of customers).

The present industry structure is illustrated in Figure 3.4.

### 3.4. Current Structure of the Sector

#### 3.4.1. Generation

During the last 2 decades, Sri Lanka’s electricity generating system has been in transition from one dominated by hydro to a mixed hydro–thermal system, with the thermal power fueled mainly by imported oil. In 2012, oil-fired thermal power provided nearly 60% of electricity generation, and hydropower provided 23% (Table 3.2). There was a major shift to hydropower in 2013, which provided 50% of generation, with oil-fired thermal power contributing only 28%. In 2012, 7% of generation was from nonconventional renewable energy (NCRE). The National Energy Policy set a target of 10% generation from NCRE sources by 2015, which was already achieved in 2013. Table 3.3 provides the details of the types of NCRE power plants operating on the grid in 2013.

Figure 3.4: Sri Lanka—Functionally Unbundled Monopoly (2009 on)

CEB = Ceylon Electricity Board, D1 = Distribution 1, D2 = Distribution 2, D3 = Distribution 3, D4 = Distribution 4, IPP = independent power producer, LECO = Lanka Electricity Company Ltd.

Note: CEB generation, transmission, and four distribution regions are now separately licensed, but all report to the same Board. IPPs, small power producers, and the LECO are also licensed.

Source: Kumarasinghe (2014)
In 2013, seven IPPs were operating; all used oil-burning diesel engines and combined cycles. Their total capacity was 711 megawatts. Three smaller IPPs have since come to the end of their contracts. Only a few IPPs were contracted through a formal, competitive bidding process with strict guidelines; others were operating on negotiated contracts. IPPs are paid on a two-part tariff, covering capacity and energy, allowing the single buyer (the CEB Transmission Licensee) complete freedom to dispatch all power plants in the system (major hydro, the CEB’s own thermal plants, and IPPs) on commercial terms. The output of SPPs, all using NCRE, is purchased at all times up to contract capacity with no limitation. However, these are not “take-or-pay contracts,” because if for any reason (such as a transmission outage) their outputs cannot be purchased, there is no payment.

Currently small hydropower plants are developed as grid-connected private power plants feeding the grid on a commercial basis. By the end of 2013, 131 small privately owned hydroelectric power plants were connected to the grid, with an aggregate capacity of about 267 megawatts. Over 300 micro hydropower plants (typically producing less than 20 kilowatts) were also used to provide the basic electricity needs of remote communities with no involvement of the grid or the CEB. About 50 off-grid micro hydropower plants (typically producing less than 100 kilowatts) were still in use by tea or rubber estates to provide power to estate factories and bungalows. A few of them have been connected to the grid on the basis of net metering regulations.

The views on the role of IPPs and SPPs in Sri Lanka are mixed. The initiative has allowed relatively
quick procurement of power plants when faced with delays in the CEB’s mainstream investment program, and this has helped avoid load shedding. However, all the IPPs commissioned are high-cost oil-fired power plants, with considerably higher cost than coal-based or hydro alternatives.

The opening of renewable energy development to the private sector has also brought mixed results. The country has now developed almost all its small hydropower resource sites through this initiative, and Sri Lanka is cited as an example of how the private sector can enter an area a conventional utility may not be interested in developing—small site-specific renewable energy facilities. However, Sri Lanka’s experience in developing biomass-based power generation and wind power with the private sector is not considered a success. The expected large-scale biomass plantations did not materialize and power plants are limited to those using agro-residues. Wind power feed-in tariffs designed to encourage investment rose dramatically to more than 20 United States cents per kilowatt-hour (kWh), which is more than double the average generation cost and is an unsustainable level for the procurement of power. These feed-in tariffs have been discontinued and as yet no alternative subsidy has been provided.

Table 3.4 shows the distribution of capacity by technology and by ownership type in mid-2014; Figure 3.5 shows the distribution of capacity between the CEB, IPPs, and SPPs from 1990 to 2013. While the CEB remains the dominant producer, its share of capacity has been declining since 2000 and this decline has accelerated in recent years.

In relation to supply vulnerability, over time Sri Lanka has come to depend on imported oil to fuel a major share of its generation. Given the fixed nature of the power purchase agreements (PPAs) with oil-fired generators, the cost of power is vulnerable to the high cost and volatility of oil import prices, affecting the overall affordability of power. Measures are being taken to reduce this vulnerability, notably construction of some coal-fired plants, introduction of renewable energy, and a review of PPAs with a view to future renegotiation. Of these measures, only the coal-fired plants offer any real opportunity for system cost reduction. The subsidy required by renewables is well above system average costs, and the review of PPAs offers only the potential for revising new contracts.

Using more renewable power is planned as an additional security measure to relieve dependence on fossil fuel imports. Conventional hydropower is currently the dominant source of renewable energy used for electricity generation (82.7% of renewable-based power generation to the grid in 2013), followed by small hydro (13.7%), wind energy (3.3%), and biomass (0.4%). Solar photovoltaic systems provide a small amount of energy to the

<table>
<thead>
<tr>
<th>Resource</th>
<th>Type</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewables</td>
<td>CEB Hydro</td>
<td>1,356</td>
</tr>
<tr>
<td></td>
<td>CEB wind</td>
<td>3</td>
</tr>
<tr>
<td>Small Renewable</td>
<td>Private hydro</td>
<td>281</td>
</tr>
<tr>
<td>(SPPs)</td>
<td>Private biomass</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td>Private wind</td>
<td>99</td>
</tr>
<tr>
<td></td>
<td>Private solar</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Total renewable</td>
<td>1,758</td>
</tr>
<tr>
<td>Thermal</td>
<td>CEB oil-fired</td>
<td>537</td>
</tr>
<tr>
<td></td>
<td>CEB coal-fired</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td>Private oil-fired: IPP</td>
<td>796</td>
</tr>
<tr>
<td></td>
<td>Total thermal</td>
<td>1,933</td>
</tr>
<tr>
<td>Total installed capacity</td>
<td></td>
<td>3,691</td>
</tr>
<tr>
<td>Peak demand in 2013 (excluding small renewables)</td>
<td>2,152</td>
<td></td>
</tr>
<tr>
<td>Surplus (excluding small renewables)</td>
<td>1,139</td>
<td></td>
</tr>
<tr>
<td>Reserve Margin</td>
<td></td>
<td>53%</td>
</tr>
</tbody>
</table>

CEB = Ceylon Electricity Board, IPP = independent power producer, MW = megawatt, SPP = small power producer (with capacity less than 10 MW).
Sources: CEB (2013a, 2014b).
3. Power Sector Reform in Sri Lanka

3.4.2. Transmission and Distribution

The license for transmission and bulk supply is held exclusively by the CEB, as stipulated in the Electricity Act of 2009. The transmission network (Figure 3.6) consists of 62 grid substations (132/33 kilovolts [kV], 220/132/33 kV, 220/132 kV, and 132/11 kV) and about 2,436 kilometers of high-voltage lines (both 220 kV and 132 kV). Since war damage in the northern Jaffna peninsula has been repaired, the transmission grid now covers the whole country. The rehabilitation of the transmission or distribution network has resulted in zero incidence of load shedding. Under the Electricity Act of 2009, the CEB distribution activities were subdivided into four functional divisions operating separately (Figure 3.7).

3.4.3. Tariff Policy

As the electricity sector regulator, the PUCSL is responsible for overseeing and in some cases setting the acceptable level of prices, service quality, and competition in the sector. Following the regulatory requirements under the Electricity Act of 2009, in 2011 the PUCSL published for the first time the comparative costs of all thermal and hydroelectric power plants considerably cheaper than the IPP and SPP generators. One reason for this, beside economies of scale, is that CEB power plants were usually elements of the least-cost long-term power sector plan. By contrast, most IPPs were not: most were small-scale plants, some were negotiated in haste, and some were established in locations unsuitable for transport of fuel.17

All generation is priced on the basis of PPAs between the CEB Transmission Licensee and each generation licensee.18 Generation costs are passed through

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17 For example, four oil-fired power plants, all IPPs, are between 40 and 125 kilometers from Colombo. Fuel has to be transported to them by road, increasing costs and traffic congestion.

18 Because the CEB Generation Licensee is not a separate corporate entity (owing to the form of business units of CEB established through the Electricity Act of 2009), it sells on the basis of a memo rather than through a legally established PPA. Other IPPs and SPPs sell to the CEB Transmission Licensee.
Figure 3.6: Sri Lanka—Power Plants and the Transmission Network

This map was produced by the cartography unit of the Asian Development Bank. The boundaries, colors, denominations, and any other information shown on this map do not imply any judgment on the legal status of any territory, or any endorsement or acceptance of such boundaries, colors, denominations, or information.

$kV = \text{kilovolt.}$

Note: Nonconventional renewable energy power plants (small hydro, wind, and biomass) are not marked.

Figure 3.7: Sri Lanka—Functional Divisions of the CEB Distribution System

DL = distribution licensee.
by the purchaser in transmission to distribution. Distribution licensees pass the generation costs through to end users. The CEB Transmission Licensee and each distribution licensee should not make a profit or a loss from buying power from generation companies and selling it to end users. On the retail side, generation and transmission costs should also be passed through to end users with no profit or loss.

In 2009, the PUCSL started discussions with licensees about a new tariff methodology to unbundle rates, and to address the issue of transfer prices and subsidies. The CEB had accumulated large debts over the years as a result of subsidies established by government policy, and this needed to be addressed. In principle a new tariff methodology became effective in January 2011, resulting in a tariff schedule that (i) reflects separately the costs of each generating, transmission, and distribution licensee providing electricity at specified times of the year, days of the week, and times of the day; and (ii) permits each licensee to recover all reasonable costs incurred in efficiently carrying out the activities authorized by its license. The principle is that each licensee is “ring fenced,” making the licensee responsible for the components of its business that are within its control and compensated for external features of the business that are not within its control. The components of the tariff are grouped as follows:

- bulk supply tariffs (for use of the transmission system and the tariff related to electricity generation);
- distribution tariff (for use of the licensee’s distribution system); and
- retail supply tariff (the cost of supplying electricity from the distribution system to the customer).

The full implementation of the tariff methodology has been delayed, however. Table 3.5 gives the original road map for tariff reform published in 2010. The tariff methodology and the implementation procedure are in place, but further progress is in serious doubt owing to significant delays in implementing tariff adjustments both for customer and bulk supply tariffs, and the consequent erosion of public confidence in the tariff-setting process.20

### 3.5. Limitations of Reform

The reform process has focused on restructuring the CEB and the associated regulatory bodies and the achievements of unbundling and tariff setting are still limited. Nonetheless, access to the grid is wide (87% in 2012 according to Population and Household Survey 2012 and 96% in 2013 according to the CEB),21 transmission and distribution losses are low (9.5% of net generation for the CEB in 2013 and 6.6% for the LECO),22 and the generation system is not subject to frequent or continuous load shedding.23 Physical security and reliability of supply, two reform goals, have been achieved, although definite grid and distribution codes have not yet been implemented. But these achievements cannot be clearly attributed to the formal reform-related or restructuring initiatives. They are rather more likely due to political initiatives during the last several decades—the programs to accelerate electrification, and to build power plants to meet the growing economy’s need for power. Indicators for improved system performance are considered separately in more detail in Chapter 5. Here, achievements in relation to other initial goals of reform are considered: improving the economic efficiency and profitability of the sector; improving regulation to provide good governance; and insuring transparency in pricing, management, and regulation.

20 This is despite the PUCSL being fully empowered to issue tariff orders to recover costs.
21 Department of Census and Statistics (2014) and CEB (2013b). The different electrification rates reported can be due to different definitions of customers. The CEB adds all household customers and a share of commercial customers who conduct small businesses to calculate the number of electrified households. The CEB’s accounts include a high share of customers whose accounts are zero, indicating they are inactive. Thus, the actual ratio is lower than the CEB figure.
22 Data from the Sri Lanka Sustainable Energy Authority, 2013 Sri Lanka Energy Balance.
23 The last major load shedding was in 2001–2002. Limited load shedding for about 4 weeks was required in August 2012 owing to a power plant outage and a severe drought.
3. Power Sector Reform in Sri Lanka

The power sector has not solved the financial problems. The hope was that improved accountability of smaller business units and transparent cost-reflective pricing would gradually move them to profitability. However, although a widely discussed tariff methodology and a price revision cycle are available, there is no indication about when they will be fully implemented. Prescribed monthly price adjustments and changes to the structure of the tariff have been missed, ignored, or not implemented, without any announcement from the PUCSL.

Further changes in the sector’s structure are being contemplated. A wholesale market with limited competition is being considered for 2016. This could involve moving the IPPs to a competitive market, introducing merchant power plants, and allowing the wheeling of power, initially between the same legal entities (for example, from a micro hydro in a tea estate to the company headquarters in the city).

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Table 3.5: Sri Lanka—Road Map for Tariff Reforms and Rebalancing

<table>
<thead>
<tr>
<th>Year</th>
<th>Households</th>
<th>Religious Establishments</th>
<th>Other Retail (industry, general, hotel)</th>
<th>Bulk Consumers</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>Continue the lower tariffs for low-income groups.</td>
<td>25% reduction.</td>
<td>Introduce a category for government schools, hospitals, and divisional secretariat offices.</td>
<td>• TOU tariffs made mandatory for Industrial consumers. • Flat tariffs mandatory for other group of consumers.</td>
</tr>
<tr>
<td>2012</td>
<td>Reduce the number of blocks.</td>
<td>No changes.</td>
<td>Reduce the price gap between the classes of customers.</td>
<td>• All classes of bulk customers to be unified and TOU tariffs to be mandatory. • Introduce a charge for reactive power.</td>
</tr>
<tr>
<td>2013</td>
<td>Reduce number of blocks.</td>
<td>No changes.</td>
<td>No difference between the customer classes, except in terms of voltage at which service is provided. For the purpose of retaining a database, customer classification will be retained in the accounting system. TOU tariffs will be mandatory for all retail and bulk customers in industry, hotel, and general purpose categories. Any subsidies will be addressed outside the licensee tariffs.</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>Retain 3 blocks. Optional TOU tariff for all 3-phase customers. Tariffs yield adequate revenue to break even, meet all commitments including debt service, but excluding a return on assets to the government.</td>
<td>No changes.</td>
<td>No further changes.</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>Abolish block tariffs. Optional TOU tariffs to all customers. Tariffs to all customers are targeted to be fully cost reflective. Government earns a return on assets on the sector.</td>
<td>No changes.</td>
<td>No further changes.</td>
<td></td>
</tr>
</tbody>
</table>

TOU = time of use.
Source: PUCSL (2010)

One of the main reasons for the sector’s poor financial condition is the ad-hoc and negotiated pricing for power, dictated by different governments over the years. As a result, CEB debts have accumulated from years of not charging tariffs to cover costs. Some improvements have been made, but revenues still do not completely cover system costs, and do not provide a potential for debt reduction. The long-term debt as of 2012 exceeded SLRs200 billion (about $1.8 billion), and under current conditions is projected to increase significantly by 2015. Average income from sales has not increased significantly since 2008, while costs have increased.\(^{24}\) The benefit of reducing network losses is buried in the large financial deficits. Electricity sector reform and unbundling were seen as attractive solutions, but restructuring the power sector has not solved the financial problems. The hope was that improved accountability of smaller business units and transparent cost-reflective pricing would gradually move them to profitability. However, although a widely discussed tariff methodology and a price revision cycle are available, there is no indication about when they will be fully implemented. Prescribed monthly price adjustments and changes to the structure of the tariff have been missed, ignored, or not implemented, without any announcement from the PUCSL.

Further changes in the sector’s structure are being contemplated. A wholesale market with limited competition is being considered for 2016. This could involve moving the IPPs to a competitive market, introducing merchant power plants, and allowing the wheeling of power, initially between the same legal entities (for example, from a micro hydro in a tea estate to the company headquarters in the city),

\(^{24}\) Average income per unit for 2008–2011 was SLRs13.25/kWh. Losses in 2008 and 2009 amounted to SLRs33.9 billion and SLRs31.2 billion, respectively (CEB, Annual Report [various years]).
Assessment of Power Sector Reforms in Asia

and within local areas (for example, from one block of a large tea estate to another block, using the local utility distribution network) and subsequently from one entity to another. To establish a wholesale market, tariffs for all affected parties would have to be reviewed and revised. More substantial reform going beyond the Electricity Act of 2009 would extend the unbundling process to establish independent companies out of the 6 CEB licensees. These would report to the CEB Holding Company, but operate as separate profit centers, similar to the arrangement in place for the government-owned distribution company, LECO.

However, the reform needed most urgently is the institution of efficient pricing for electricity, and the implementation of least-cost, long-term investment planning. Since 2009, these have been introduced in part or at least on paper, but the implementation has been incomplete at best. With efficient pricing, the lack of capital for investment and expansion, and the financial stress of accumulating deficits, could be remedied over time. However, while a tariff methodology and an implementation procedure have been established, their use is in serious doubt. End-use tariffs are still adjusted on an ad hoc basis without moving toward cost-based pricing. Transmission and distribution costs are not submitted to the PUCSL in a timely fashion, further frustrating efficient and timely cost-based pricing.

For transparency and efficiency in operations, the revenue streams of the different licensees must be separated and allocated properly. Despite the CEB’s partial unbundling, its four distribution licensees and the Transmission Licensee have not been made independent of each other and from the CEB corporate accounts, so the distribution of income from sales to customers and of the sales from the Transmission Licensee to the LECO continues to be credited to the general CEB corporate account. The CEB Transmission Licensee should manage the bulk supply transactions account transparently, reporting both to the PUCSL and to the public, as required under the tariff methodology. Full disclosure of costs of supply on customer bills, information on provision of licensee performance, and information on allowed revenues and losses need to be provided and generation cost control measures need to be instituted. As with tariffs, many of these changes are required on paper, but remain to be implemented.

Truly independent regulation and operation of the system is essential for tariff reform. Neither the PUCSL nor the CEB can make independent decisions without government interference to block politically unpopular moves. This tends to create a nontransparent, ad hoc, and sometimes distortionary process of decision making with a general lack of transparency in both tariff making and regulation. Despite the new regulatory regime established in 2010, the CEB Transmission Licensee continues to make decisions on selection and design of mainstream power generation projects, in association with the prereform administrative structure. A new procedure should be established in consultation between the PUCSL and the CEB Transmission Licensee to ensure a transparent review of the generation expansion plan and of PPAs, including feed-in tariffs and other preferential and nontransparent PPA provisions. Technical regulation of the distribution and grid codes also needs to be agreed jointly by the PUCSL and the licensees, and implemented.

The needs for efficient and transparent pricing and for independent regulation were both addressed in phase two of the reform process. But the principles established by law have not yet been implemented. This omission is at the root of inefficiencies in the sector and provides a basic rationale for further reform.

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In December 2013, for the first time, the PUCSL issued the Long-Term Generation Expansion Plan of the CEB for public comment.
4. POWER SECTOR REFORM IN VIET NAM

4.1. Background to Reform

Viet Nam is a densely populated lower-middle-income country in Southeast Asia that encompasses a territory of more than 330,000 square kilometers and had about 90 million people in 2013. Reform of its socialist central planning system has been ongoing since 1986, with an explicit attempt to introduce allocation by markets into the previously relatively rigid planning system. The country has been one of the new “Asian Tiger” economies during the last 20 years, and its annual average growth exceeded 6.8% during 1990–2013. In the same period, the country’s per capita gross domestic product more than trebled in real terms, from $301 in 1990 to $1,029 in 2013, in 2005 $ (Figure 4.1). Table 4.1 summarizes Viet Nam’s socioeconomic development during 1990–2013.

A key driver of the country’s rapid growth has been the expansion of industry, which increased its share of gross domestic product from 26% in 1990 to 38% in 2013. The demands of a rapidly growing economy implied a clear need to raise electrification rates, particularly in rural areas, and to create institutions that were financially viable and adaptable enough to improve system efficiency. The electrification rate has increased significantly, but most of the increase occurred prior to the formal institution of reform of the sector.

For the last 2 decades, Viet Nam has been self-sufficient in energy; an important coal, oil, and natural gas producer; and a significant exporter of coal. Its substantial proven reserves include fossil fuel and hydro resources. Viet Nam’s electricity capacity is

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**Figure 4.1: Viet Nam—GDP per Capita (2005 $) and GDP Growth (%), 1990–2013**

![Graph showing GDP per capita and GDP growth from 1990 to 2013](image)

GDP = gross domestic product.

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26 Information and data on Viet Nam in this section and subsequent chapters come from ADB (2015c), except as otherwise indicated.
Assessment of Power Sector Reforms in Asia

A mix of hydropower, gas-fired, oil-fired, and coal-fired plants and has been expanded significantly in recent years with heavy government investment. Hydro capacity has become the dominant source in recent years (Figure 4.2). Per capita electricity consumption has grown significantly, reflecting major improvement in electrification rates and the rapid growth of the economy.

Before 1995, Viet Nam’s power sector was government-owned, with the Ministry of Energy managing three regional power companies, each responsible for generation, transmission, and distribution within its own territory. Some restructuring began as early as 1995, with the creation of the utility Electricity of Viet Nam (EVN), reflecting a broader reform program (Doi Moi) that started in 1986. The more explicit power sector reform can be considered to have started in July 2005, when the Electricity Law of 2004 came into force. Drivers of this reform were the need to meet the demands of the rapidly growing economy and to remedy the pricing inefficiencies in the power sector, which had resulted in a lack of investment to fund system maintenance, improvements, and expansion.

4.2. Unbundling and Restructuring of the Power Sector

Over time, as part of the government’s commitment to reform, the government-owned power company Electricity of Viet Nam, renamed Viet Nam Electricity (but retaining the EVN abbreviation), was reorganized into a holding company, with many of its generating plants dispersed into separate companies. Its market share has fallen to about 70% of installed capacity and 50% of the generation...
market. An independent unit, the National Power Transmission Corporation, was established to manage transmission separately from generation and ultimately to permit competitive power marketing. Distribution companies were rationalized and integrated more fully into the national grid. There were also major government investments in system capacity and expansion and in improved management and service delivery at the level of generation, transmission, and distribution, which enabled the rapid growth of power consumption.

The EVN monopoly started to break up as early as 2000 with the introduction of independent power producers (IPPs). In that year, IPPs accounted for about 7% of total capacity (452 megawatts [MW]) and about 9% of total generation (2.51 terawatt-hours [TWh]). In 2003, the government began to partly restructure the EVN, selecting several generation and distribution assets for corporatization into joint stock companies and selling shares to other government-owned companies, in a process referred to in Viet Nam as “equitization.”

### Box 4.1: Viet Nam—Revised Road Map of Power Sector Reform

<table>
<thead>
<tr>
<th>Competitive Generation Market</th>
<th>Electricity Wholesale Market</th>
<th>Electricity Retail Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 July 2012</td>
<td>2015</td>
<td>2021</td>
</tr>
<tr>
<td>Pilot Operation</td>
<td>Full Operation</td>
<td>Full Operation</td>
</tr>
<tr>
<td>2017</td>
<td></td>
<td>Full Operation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pilot Operation</td>
</tr>
<tr>
<td>2021</td>
<td></td>
<td>Full Operation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2023</td>
</tr>
</tbody>
</table>

**Phase 1 (up to 2014) — Competitive Generation Power Market.**
- Implement the single buyer and the power market.
- Complete the competitive generation power market with participation of independent power producers that are already in the single buyer arrangement.
- Implement a spot market, where all generators are able to participate.

**Phase 2 (2015–2021) — Competitive Wholesale Power Market.** Entails expanding demand-side participation in the organized power market by replacing the single-buyer model with an arrangement whereby consumers may negotiate direct purchases of power independent of the single buyer.

**Phase 3 (2021, to full operation by 2023) — Competitive Retail Power Market.** Split distribution company activities into network management and operation; and retailing, with end users served by the distribution company and free to choose their suppliers.

The original road map sets the pilot operation of the Competitive Generation Power Market from 2005 to 2008, with the following strategies:

1. Organize a competitive generation market among the generators owned by Viet Nam Electricity (EVN) to test the single-buyer model.
2. Reorganize generation, transmission, and distribution companies in the EVN into independent accounting units.
3. Allow existing independent power plants not owned by the EVN to continue selling to the EVN according to their long-term power purchase agreements.
4. Establish the market operator and the single-buyer entity under the EVN.
5. At the end of the pilot phase, reorganize the large-scale EVN generators into independent state-owned joint-stock companies.

**Source:** Ministry of Industry and Trade website: Prime Minister Decisions No (i) 26/2006/QĐ-TTg dated 26 January 2006 approving the roadmap and conditions for the formation and development of the different levels of the electricity market; and (ii) 63/2013/QĐ-TTg dated 8 November 2013 providing for the roadmaps, as well as conditions and structure of the electricity branches to form and develop the levels of electricity market.
following year, it was proposed that the EVN would retain full ownership and control of the three large multipurpose hydropower projects (about 30% of installed capacity), but that its remaining eight generating plants (48% of total capacity) would be equitized. A small number of privately held or foreign-owned IPPs, built and developed under existing power purchasing agreements, made up the remaining capacity (approximately 22%) in 2004.

The road map for power reform is clear, starting with a single buyer for power, proceeding to a competitive wholesale market and finally to a competitive retail market. The original road map envisaged an initial pilot stage with limited competition among selected state-owned generators and a single buyer, to be introduced by 2009; the competitive wholesale market by 2017; and the competitive retail market by 2023. Implementation has slipped from this schedule, with the pilot competitive generation market only starting in 2012. Lengthy processes of developing new regulations on power prices to be adopted in the generation market, drafting power purchase agreements, and developing information technology infrastructure for market operations caused the delay (Energy Alliance 2012). On 8 November 2013, the Prime Minister issued Decision No. 63/2013/QD-TTg, which provides an updated road map and sets out the conditions and organization structure for future power market development (Box 4.1).

4.3. Reform after 2004

The National Power Transmission Corporation was established in 2008 based on the reorganization of the EVN’s four transmission companies and three power grid management boards. The National Power Transmission Corporation is 100% owned by the EVN and is responsible for managing the transmission grid. The Electricity Power Trading Company, established in 2008, is also part of the EVN and plays the role of a single buyer in the generation market. The National Load Dispatch Centre, the system operator, is also part of the EVN, although the intention is that it will ultimately become independent at the start of the competitive wholesale market. Independence of the system operator from generation interests is generally viewed as essential for effective competition and for attracting private sector investment. In 2010, the 11 regional distribution companies within the EVN were reorganized into 5, now called power corporations. These are single-owner limited companies 100% owned by the EVN, responsible for supplying power and maintaining the distribution grid up to 110 kilovolts (kV) across 5 areas of the country (Central, North, South, Ho Chi Min City, and Ha Noi).

In 2012, the EVN’s generation operations were reorganized into three power generation companies. They are single-owner limited companies initially 100% owned by the EVN and operating as divisions within the EVN holding company structure. They are to be fully separated from the EVN when the competitive wholesale market begins to operate. The ultimate goal is to seek equitization for these companies. The EVN will, however, retain ownership and operating control over these three strategic multipurpose hydropower projects whose operations have implications for irrigation and flood control (Figure 4.3). Box 4.2 summarizes the key institutions in the Viet Nam power sector.

The EVN has successfully held initial public offerings for three generation companies (Vinh Son–Song Hinh and Thac Ba hydropower plants and Pha Lai Thermal Power Plant) and one distribution company (Khanh Hoa Power Company). From 2007 to 2009, four more initial public offerings succeeded (Ninh Binh and Thu Duc thermal power plants and Danhim–Ham Thuan–Dami and Thac Mo hydropower plants), and joint stock companies were established for investment in generation, with participation of other investors (either other state-owned companies in the form of IPPs or foreign investors as build-operate-transfer [BOT] projects). Foreign investment currently can be approved for participation in generation, although interest from foreign entities has been limited. The intention is for the EVN to purchase more power from IPP and BOT projects in the longer run as it concentrates on large hydroelectric and nuclear projects and relies on others to develop thermal power plants.
Figure 4.3: Viet Nam—Structure of the Power Sector

Box 4.2: Key Institutions of the Viet Nam Power Sector

BOT = build–operate-transfer, EVN = Viet Nam Electricity, IPP = independent power producer, SMO = system and market operator.
Source: Toan (2014).

BOT = built, operate, and transfer; C = consumer; DC = distribution company; D-e = equitized distribution company; EECO = Energy Efficiency and Conservation Office; EPTC = Electric Power Trading Company; ERAV = Electricity Regulatory Authority of Viet Nam; EVN = Viet Nam Electricity; G = EVN-owned generation company; GDE = General Directorate for Energy; G-e = equitized generation company; IE = Institute of Energy; IPP = independent power producer; MNRE = Ministry of Natural Resources and Environment; MOF = Ministry of Finance; MOIT = Ministry of Industry and Trade; MPI = Ministry of Planning and Investment; NLDC = National Load Dispatch Centre; NPT = National Power Transmission Corporation; SB = single buyer; SMO = system and market operator.
Sources: Websites of the Ministry of Industry and Trade, Ministry of Justice (for the 2004 Electricity Law), Institute of Energy, and Renewable Energy and Energy Efficiency Partnership; Agence Française de Développement (2012); and Nam, Quan, and Binh (2012).

continued
The **Prime Minister of Viet Nam** is responsible for approving policies and regulations for the power sector.

The **Ministry of Industry and Trade (MOIT)** is responsible for managing the energy sector. The MOIT formulates reform initiatives and the national electricity development plans (subject to approval by the Prime Minister) and supervises their implementation; reviews, approves, and publicizes new investments in the power sector and issues licenses for electricity wholesalers and retailers and for entities involved in electricity generation, transmission, and distribution activities associated with the national electricity system; and manages energy efficiency programs and reviews and endorses retail price adjustments for approval by the Prime Minister.

The **General Directorate of Energy** is responsible for overall energy planning and policy, submits and appraises power and energy development plans and local and regional energy development plans to the MOIT, and manages build-operate-transfer power projects.

The **Energy Efficiency and Conservation Office**, which is under the MOIT, leads the implementation of the Viet Nam National Energy Efficiency Program, together with specialized institutions (the Institute of Energy, energy conservation centers, and technical universities) and social organizations.

The **Electricity Regulatory Authority of Viet Nam**, established in October 2005, is under the MOIT. The Electricity Regulatory Authority of Viet Nam assists the MOIT in regulating the operation of the competitive power market, assessing both wholesale and retail electricity tariffs as well as fees for transmission and distribution; issues guidance on the conditions and procedures for electricity outages; monitors levels of electricity supply and demand, and recommends measures to achieve supply-demand balance; establishes tariff-setting principles, including transfer pricing between sector entities, and develops tariffs for regulated activities and purchase agreements for the single buyer; and monitors the implementation of plans and investment projects for the electricity sector.

The **people’s committees** of the provinces and centrally-run cities formulate local electricity development plans and submit them to the people’s councils and to the MOIT for approval. The people’s committees also monitor the implementation of approved local electricity development plans. Within the scope of their powers, the people’s committees formulate and execute plans for clearing ground, relocating and resettling people, paying compensation for loss of land and property, and protecting land areas for power development projects. They also grant electricity activity licenses to organizations and individuals engaged in small-scale electricity activities within their jurisdiction. Together with the MOIT, ministerial-level agencies, and other government-attached agencies, the people’s committees are also involved in formulating programs and projects for promoting energy efficiency.

The **Ministry of Planning and Investment** is the lead agency that coordinates and allocates funds for energy projects that the line ministries and agencies submit for consideration and approval by the Prime Minister.

The **Ministry of Finance** has jurisdiction over taxation related to energy activities. Together with the MOIT, the Ministry of Finance promulgates the spending guidelines for formulation, appraisal, publication, and revision of electricity development plans.

The **Ministry of National Resources and Environment** and the **Institute of Energy** conduct research and development activities related to energy. The Ministry of Natural Resources and Environment is the lead agency for research and development in energy and environmental protection. The Institute of Energy serves as a research organization for the government and the EVN; conducts research on national energy strategies, policies, and development plans; and provides estimates of demand, prepares project studies, and identifies new technologies to improve energy efficiency and supply. The Institute of Energy is active in developing and promoting renewable energy. It established the Center for Renewable Energy and Clean Development Mechanisms in 2007.

**Viet Nam Electricity (EVN)** is responsible for meeting basic electricity demand for socioeconomic development, ensuring progress on power generation and transmission projects assigned in the Power Master Plan, and improving capacity for business administration, operating effectiveness, and corporate culture within the sector. Units formed under the EVN include the following:

- The **National Power Transmission Corporation** is the transmission system operator. It incorporates four transmission companies that were previously each responsible for managing transmission assets in their franchise areas. As the sole transmission owner, the National Power Transmission Corporation’s responsibilities include

  continued
4.4. Competitive Generation and Wholesale Markets

The competitive generation market of Viet Nam aims to achieve stable power supply and price, attract investment to the sector, encourage competition in the generation market and promote transparency in market and system operations and electricity pricing. Licensed power plants, excluding wind and geothermal power plants, with installed capacity equal to or greater than 30 MW and connected to the electricity grid are required to compete in the market. Hydropower plants are given no more than 6 months from the commencement of commercial operations to participate in the market, while thermal power plants have a grace period of 12 months. These include 35 indirect (including 11 strategic multi-purpose plants) and 48 direct trading generators—Figure 4.4 (Huy 2014). On the other hand, power plants that have an installed capacity less than or equal to 30 MW and are connected to the 110-kV power system and satisfy the conditions of infrastructure and the operational requirements of the electricity market (excluding wind and geothermal power plants) may choose to participate in the electricity market. BOTs and small power plants (including those in industrial zones that sell part of their generated energy to the national power system, but are unable to maintain a stable long-term selling plan for this energy amount) are not required to participate in the competitive generation market. Since the competitive generation market started operating, about 35% of total installed capacity of the national system is traded on that market, including from all generation companies (World Bank 2014).
In terms of market development, electricity is currently traded through either definite-term contracts or spot trading. A small pilot competitive generation market started in 2012 and generating companies and IPPs now compete in a power pool to sell to the single buyer (the Electricity Power Trading Company). However, only 10% of sales are made at spot market prices and 90% of sales prices are negotiated in contracts between the generator and the single buyer. Foreign-owned BOT investors sell all output to the single buyer at long-term contract prices set by negotiation between the investor and the Ministry of Industry and Trade (MOIT). These are negotiated case-by-case, with a cost component reflecting the technology used (thermal or hydro) and a component specific to the plants involved. Because of the need to balance generation with possibly conflicting responsibilities for managing flood control and irrigation, the large multipurpose hydro generators sell at cost-based prices determined by the MOIT.

Although the competitive generation market is still in its infancy, there has been marked improvement in transparency in generation scheduling and energy wholesaling activities since its operation. In addition, the Electricity Regulatory Authority of Viet Nam notes that generation prices now adjust to variations in generators’ costs and hourly system demand. Generators have also been keen in reducing the cost of generation and optimizing their operation/maintenance activities (Huy 2014).

4.5. Tariffs

Under the promulgated and revised tariff scheme, retail tariffs must be approved by the MOIT or the...
Prime Minister and are intended to reflect changes in cost. Retail tariffs are recalculated every 6 months and submitted for approval. Policy also aims to improve demand-side energy efficiency by setting efficiency standards for appliances, introducing time-of-use metering for all customers using more than 2,000 kWh per month, promoting awareness campaigns, and providing support for programs such as solar water heating. From 2005 to 2013, average tariffs rose by 6% annually. Figure 4.5 illustrates the tariff setting process.

Special tariffs apply to renewable generation, providing preferential pricing for renewable power. Small hydro plants (under 30 MW) are eligible for an avoided cost tariff, set annually based on the estimated cost of the marginal thermal generator on the system. Because wind power generally cannot be developed without a subsidized price, wind generation enjoys even more preferential pricing. The tariff for wind currently is set as a specified guaranteed feed-in tariff of United States (US) cents 7.8/kWh (including a US cent 1/kWh contribution from the Viet Nam Environmental Protection Fund). The Prime Minister Decision 31/2014/QĐ-TTg of 20 June 2014 provides the feed-in tariff for solid waste-to-energy power suppliers of up to VND2,114 (about 10.05 US cents) per kWh).

Transmission tariffs are calculated and charged separately, as are auxiliary services. Criteria for performance-based transmission rates are not yet established. The transmission charge is set by the National Power Transmission Corporation and

**Figure 4.5: Viet Nam—Electricity Tariff-Setting Structure**

**BOT = build-operate-transfer, EPTC = Electricity Power Trading Company, ERAV = Electricity Regulatory Authority of Viet Nam, EVN = Viet Nam Electricity, Genco = generating company, IPP = independent power producer, NLDC = National Load Dispatch Centre, NPT = National Power Transmission Corporation, PC = power corporation, PPA = power purchase agreement, SB = single buyer, SMHP = strategic multipurpose hydropower plant, SMO = system and market operator, TNO = transmission network owner.**

Source: Toan (2012).
approved by the MOIT. Approval of retail tariffs involves the MOIT, the Ministry of Finance, and the Prime Minister.\footnote{Based on Prime Minister Decision No. 69/2013/QĐ-TTg issued on 19 November 2013.}

### 4.6. Current Structure of the Electricity Sector

Currently, the reform program operates under the general direction of the National Master Plan for Power Development for 2011–2020 Period with the Vision to 2030 (or the PMP VII) of 21 July 2011. The PMP VII envisages in the long-run a completely competitive electricity sector, including full wholesale and retail competition. The aim is to combine the efficient use of domestic energy resources with the reasonable import of electricity and fuels, and to diversify primary energy resources. Furthermore, the PMP VII set specific targets. Box 4.3 summarizes the goals set in the plan.

Figure 4.6 provides an overview of the sector showing the pattern of installed and available capacity during 2000–2013. The total installed capacity in 2000 was 6,437 MW. Since then it has grown annually at about 13\%, to 31,474 MW in 2013. Capacity and generation have remained sufficient to meet both average and peak demand.

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**Box 4.3: Viet Nam—Objectives of the Power Master Plan VII for 2011–2020**

The development perspectives of the National Master Plan for Power Development for 2011–2020 Period with the Vision to 2030 (PMP VII) are as follows:

(i) Develop the electricity sector in conjunction with the national socioeconomic development strategies, and ensure an adequate supply of electricity for the national economy and social life.

(ii) Utilize the national energy resources effectively for electricity development in combination with the reasonable import of electricity and fuel, diversification of primary energy sources for electricity production, conservation of fuel, and enhancement of energy security for the future.

(iii) Gradually improve the security of electricity supply. Implement electricity prices according to the market mechanism to encourage investment in power development, and encourage effective conservation of electricity.

(iv) Develop power and protect natural resources and the environment to ensure the country’s development is sustainable.

(v) Gradually establish a competitive electricity market, with diversification of power investment and trading. The state will only monopolize the power transmission grid to ensure security of the national energy system.

(vi) Develop the electricity sector through the proper and efficient use of each region’s primary energy resources. Continue to promote rural electrification, and ensure adequate, continuous, and safe provision of electricity nationwide.

The general objective of the PMP VII is to achieve efficient use of energy resources in the country in combination with import of primary energy for power production, to supply adequate power with increasing quality and at a reasonable price for socioeconomic development and to ensure national energy security.

The PMP VII’s specific objectives are to

(i) provide adequate electricity for domestic demand; to this end, electricity production and imports will be 194–210 billion kilowatt-hours (kWh) in 2015, 330–362 billion kWh in 2020, and 695–834 billion kWh in 2030;

(ii) prioritize the development of renewable energy sources for electricity production, increasing the share of electricity produced from such sources from 3.5\% of total electricity production in 2010 to 4.5\% in 2020 and 6.0\% in 2030;

(iii) reduce the electricity elasticity coefficient relative to gross domestic product from the current average of 2.0–1.5 in 2015 to 1.0 in 2020; and

(iv) accelerate the program of electrification in rural and mountainous areas to ensure that in 2020 nearly all rural households have access to electricity.

4.6.1. Generation

Viet Nam’s generation capacity has been expanded significantly. From 2006 to 2010, through the EVN, the government invested about $10 billion in the power sector, equivalent to nearly 7% of total national capital investment in that period. Of this, 46% was for adding to the system 25 generators (in 19 power plants, with a total installed capacity of 10,409 MW).

In recent years, the major type of installed capacity has alternated between hydropower and thermal-fired plants. Thermal is now dominant, accounting for nearly half of installed capacity in 2013. But the share of hydro has also been growing rapidly, most significantly in 2012 with the opening of the EVN’s IPPs and the 2,400-MW Son La hydropower plant. Coal-fired capacity expanded from 10% of the total in 2000 to 23% in 2013. Imports of electricity started in 2009 at 700 MW, growing to 1,000 MW in 2013 (Table 4.2). Table 4.3 provides details on installed capacity and generation by fuel type. Figure 4.7 shows the growth in generation and the change in generation mix.

4.6.2. Transmission and Distribution

Before 1996, the Viet Nam power system had no 500- or 220-kV lines. Since then, the power transmission system and the distribution grid have been expanded widely, now incorporating 500-kV and 220-kV high-voltage lines, and 110-, 35-, 22-, 10-, and 6-kV medium-voltage lines. During 2006–2010, the government invested about $5 billion in grid expansion. As a result, 8,405 kilometers (km) of 110-kV–500-kV lines with a total capacity of 26,083 megavolt amperes (MVA) have been commissioned, plus 58,100 km and 13,600 MVA of medium- and low-voltage (35-kV to 0.4-kV) lines.

As of 2013, the 4,887-km 500-kV national grid lines and 19,350-MVA lines connect all regions of the country, while the 220-kV transmission lines (12,116 km and 30,251 MVA) and the 110-kV (15,602 km and 35,653 MVA) distribution lines serve 63 regional territories (Table 4.4). Additional investment has also been made in transmission to receive an incremental 940 MW of imports from the People’s Republic of China.
### Table 4.2: Viet Nam—Installed and Available Capacity, 2000–2013

<table>
<thead>
<tr>
<th>Year</th>
<th>Hydro (MW)</th>
<th>Coal (MW)</th>
<th>Gas (MW)</th>
<th>Oil (MW)</th>
<th>Imports</th>
<th>Small Hydro and Diesel (MW)</th>
<th>Others (MW)</th>
<th>Total (MW)</th>
<th>MW</th>
<th>% of Installed Capacity</th>
</tr>
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<tbody>
<tr>
<td>2000</td>
<td>3,234</td>
<td>645</td>
<td>1,250</td>
<td>200</td>
<td>0</td>
<td>454</td>
<td>654</td>
<td>6,437</td>
<td>5,742</td>
<td>89.2</td>
</tr>
<tr>
<td>2001</td>
<td>4,069</td>
<td>645</td>
<td>2,028</td>
<td>200</td>
<td>0</td>
<td>454</td>
<td>678</td>
<td>8,074</td>
<td>7,380</td>
<td>91.4</td>
</tr>
<tr>
<td>2002</td>
<td>4,069</td>
<td>1,245</td>
<td>2,428</td>
<td>200</td>
<td>0</td>
<td>454</td>
<td>699</td>
<td>9,095</td>
<td>7,967</td>
<td>87.6</td>
</tr>
<tr>
<td>2003</td>
<td>4,069</td>
<td>1,245</td>
<td>2,467</td>
<td>200</td>
<td>0</td>
<td>454</td>
<td>1,770</td>
<td>10,205</td>
<td>9,266</td>
<td>90.8</td>
</tr>
<tr>
<td>2004</td>
<td>4,069</td>
<td>1,245</td>
<td>3,084</td>
<td>200</td>
<td>...</td>
<td>454</td>
<td>1,773</td>
<td>10,825</td>
<td>10,046</td>
<td>92.8</td>
</tr>
<tr>
<td>2005</td>
<td>4,069</td>
<td>1,245</td>
<td>3,084</td>
<td>200</td>
<td>...</td>
<td>454</td>
<td>2,719</td>
<td>11,771</td>
<td>10,982</td>
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</tr>
<tr>
<td>2006</td>
<td>4,383</td>
<td>1,245</td>
<td>3,262</td>
<td>200</td>
<td>...</td>
<td>454</td>
<td>2,924</td>
<td>12,468</td>
<td>11,595</td>
<td>93.0</td>
</tr>
<tr>
<td>2007</td>
<td>4,393</td>
<td>1,545</td>
<td>3,248</td>
<td>205</td>
<td>...</td>
<td>454</td>
<td>3,871</td>
<td>13,716</td>
<td>12,948</td>
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<tr>
<td>2008</td>
<td>5,257</td>
<td>1,545</td>
<td>3,197</td>
<td>200</td>
<td>...</td>
<td>454</td>
<td>5,251</td>
<td>15,904</td>
<td>15,125</td>
<td>95.1</td>
</tr>
<tr>
<td>2009</td>
<td>6,173</td>
<td>2,145</td>
<td>3,197</td>
<td>537</td>
<td>700</td>
<td>500</td>
<td>6,163</td>
<td>19,415</td>
<td>16,813</td>
<td>86.6</td>
</tr>
<tr>
<td>2010</td>
<td>7,633</td>
<td>2,745</td>
<td>3,197</td>
<td>537</td>
<td>800</td>
<td>500</td>
<td>7,456</td>
<td>22,868</td>
<td>19,735</td>
<td>86.3</td>
</tr>
<tr>
<td>2011</td>
<td>10,120</td>
<td>4,451</td>
<td>7,434</td>
<td>912</td>
<td>1,000</td>
<td>524</td>
<td>106</td>
<td>24,547</td>
<td>22,804</td>
<td>92.9</td>
</tr>
<tr>
<td>2012</td>
<td>12,009</td>
<td>4,904</td>
<td>7,446</td>
<td>912</td>
<td>1,000</td>
<td>1,048</td>
<td>...</td>
<td>27,319</td>
<td>25,837</td>
<td>97.5</td>
</tr>
<tr>
<td>2013</td>
<td>13,260</td>
<td>7,116</td>
<td>7,446</td>
<td>912</td>
<td>1,000</td>
<td>1,740</td>
<td>...</td>
<td>31,474</td>
<td>28,737</td>
<td>94.3</td>
</tr>
</tbody>
</table>

… = no data available, MW = megawatt.

Source: Based on National Load Dispatch Centre (2014); and General Directorate of Energy (2014).

### Figure 4.7: Viet Nam—Electricity Generation: Fuel Mix, 1990–2013 (TWh)

TWh = terawatt-hour.

*Gas comprises gas used to run gas turbine and gas steam.

*Oil comprises fuel oil (including fuel oil used to run gas turbine) and diesel.

Source: National Load Dispatch Centre (2014).
4. Power Sector Reform in Viet Nam

4.6.3. Demand

Total electricity consumption grew from 11.47 TWh in 1995 to 115.06 TWh in 2013, at an average annual rate of 11%. Peak demand is estimated at 20 gigawatts.\(^{28}\) Per capita electricity consumption has been growing at an average annual rate of 12%, from 159.3 kWh in 1995 to 1,283 kWh in 2013. The growth reflects impressive improvement in electrification rates, from 50.8% in 1995 to 97.2% in 2012.

In keeping with the rapid rate of industrialization, the industry sector is the main user of power, with...
its share of total consumption rising from 40% in 1995 to 53% in 2013. During the same period, the share of households in total consumption fell from 47% to 36%. The service sector’s share remains very low, although its electricity use rose from 547 gigawatt-hours (GWh) in 1995 to 5,411 GWh in 2013 (Figure 4.8).

4.7. Recent Performance of Power Companies

The unbundling of the power monopoly is expected to improve the commercial viability of the power sector. However, positive financial and operational results may not be expected as reforms in Viet Nam have only been implemented very recently. The following discussion assesses the financial and operation performance of the EVN, generating companies, power companies, and the National Power Transmission Corporation.

From 2008 to 2011, the EVN’s annual net operating margins were negative. Its debt grew dramatically (from D$86 trillion in 2007 to D$246 trillion in 2012), and about 50% of the debt is due in less than 5 years. From 2007 to 2011, the EVN’s equity increased by 1.75 times, but its long-term liabilities increased by 2.72 times and its short-term liabilities by more than three times. In 2012, the EVN’s financial performance reversed quickly, recording a net operating margin of 13%. This was mainly due to good rainfall levels (over which EVN and other entities do not control) and to the increase in tariff rates. But with the tariff rates still not at a cost-recovery level, sustaining the improved financial performance remains a major challenge and a major deterrent to attracting investors. On a positive note, the EVN has succeeded in reducing time needed to collect revenue—from 84 days in 2008 to 68 days in 2012.

The generating companies’ finances cannot be assessed because historical data are lacking for some power plants. Nonetheless, net operating margins of most power plants with available data are lower than international standards, with coal-fired power plants performing worse than hydropower plants. Operating costs were high partly due to overstaffing (especially in thermal power plants), inefficient processes, and aged equipment. Partly because of the poor financial performance of generating companies, private investment in power generation has been minimal. In terms operational performance

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\[29\] Information in this section is from AF Mercados EMI (2013).
measured by the number of power outages, most of the generating companies’ hydropower plants performed well above the international standards. In contrast, thermal power plants had underperformed. Coal-fired power plants more than 15 years old had the highest number of outages.

Power companies and the National Power Transmission Corporation had the same financial difficulties. During 2008 to 2011, the power companies barely earned enough revenues to cover their operating costs. Their working ratios are below acceptable levels, which can be attributed to inefficient use of resources and low revenue collection because tariff rates are set below cost-recovery level. Although the situation had improved in 2012, the power companies’ net operating margins remained below a commercially acceptable level, and current account ratios were below acceptable standards.

The National Power Transmission corporation had bigger losses, with net operating margins from 2009 to 2011 (ranging from –7% to –29%). Its financial position only improved in 2012 with a net operating margin of 13%, thanks to higher tariff rates, increased transmitted electricity, appreciation of the dong and higher equity value due to revaluation of assets. Because the National Power Transmission Corporation’s financial position was unstable, it relied on debt for capital investments. In terms of operational performance, the frequency of faults in transmission lines was aligned with acceptable standards but the duration of faults had increased to 52.24 minutes from 35.37 minutes between 2009 and 2012. Low labor cost has resulted in overstaffing and has been linked to a lack of automation of processes.

Overall, generation, distribution, and transmission companies are still struggling financially. Although 2012 data indicate better performance, it is difficult to assert that the improvement is sustainable. The only consistent improvement is in the management of accounts receivable.

4.8. Limitations of Reform

The reform process has commenced functional unbundling of the industry’s monopoly structure, along with some institutional, regulatory, and pricing reforms. The EVN has theoretically been unbundled, existing as a holding company with operating divisions. Corporatization (equitization) has resulted in the creation of several state-owned joint stock companies, but little private ownership. Effective change in market structure is still limited. The initial steps toward creating a competitive electricity market have been taken, with 10% of total generated power sold under PPAs purchased in a power market by prior-day bidding. Viet Nam is already developing a legal framework for a pilot wholesale competitive market that is expected to be operational in 2017.

Clearly, the reforms and restructuring must continue to achieve complete independence among system players, including and especially the regulator, and this independence is a crucial prerequisite for implementing a competitive market. The question remains as to what extent restructuring has so far furthered the initial goals of reform.

In terms of progress toward economic efficiency and viability, some tariff reform has been introduced. As part of the reform process, the scheme for formulating tariffs has been revised to provide more efficient cost recovery, to establish cost-of-service or market-based rates, and to promote investment and efficient use of power, consistent with the government policy. Average retail tariffs are to be reviewed and adjusted annually to recover the EVN’s costs, and should be uniform throughout the country. Cost-based transmission charges and distribution tariffs are calculated on the basis of both allowed revenue and the quality of service. Criteria for performance-based transmission rates are not yet established.
So far, however, only residential and industrial tariffs are in principle designed to be cost-based while tariffs for commercial customers are not. The tariffs customers pay are supposed to be adjusted annually and quarterly according to variations in input parameters. They are unbundled for four subsectors: generation, transmission, system administration and market operation, and distribution. However, in practice, tariff adjustments have been delayed, breaking the link between tariffs and costs of supply, and transparent information on costs and revenue allocations is lacking.

Generation prices are the largest component of the retail tariff. At present, there is little possibility for reducing these through operational efficiency, as 90% of sales are covered by long-term financial PPA contracts, the prices of which are not transparent and have been negotiated between generators and the government (usually the MOIT). The PPA contracts range from 10 to 20 years for local IPPs and up to 25 years for a BOT. Special tariffs apply to renewable generation and small hydro plants, providing preferential pricing for renewable power. A new PPA pricing scheme for future thermal generators will include a bracket of permissible costs based on the benchmark of a new power plant. However, prices will still be negotiated on a case-by-case basis and include fuel transport costs.

The government has invested heavily in power sector improvements, but there are limits to public financing. As noted above, prior to reform, revenue was inadequate for operation, maintenance, and rehabilitation of existing plants, much less to accumulate investment funds for new capacity. Hence, in 2000, the government was forced to look beyond the EVN to provide continued and adequate electricity services. Entry of other generation started in 2000 with 452 MW or approximately 7.3% of total generating capacity. This doubled to 14.8% of the total in 2004 (1,575 MW). A shortage of funds for expansion has also been evident in the years since reform, as revenues continue to be inadequate for investment. Investment in generation has fallen short of the Power Development Plan VI. Only 69.1% of the planned investment had been realized by 2010—10,081 MW of the planned 14,581 MW (Table 4.5). Similarly, actual investment in the grid amounted only to 40%–60% of what was planned for 2006–2010 (Table 4.6).

The EVN is still responsible for assuring power supply and for investment in power generation, power imports and exports, and grid expansion to assure universal service. But mobilizing the capital projected as necessary for the requirements of the Power Master Plan VII may be difficult. The many varied claims for public funds limit the government’s potential for financing the power sector. Retail tariffs in principle will now include limited provisions for capital accumulation (investment in maintenance and system expansion) within a range of recoverable generation costs for new generation. In practice, such returns are not likely to be achieved and the current pricing structure may not create incentives adequate to attract significant foreign investment to the sector.

In terms of governance and regulatory reform, more aggressive changes will be needed. The EVN generation company offices, information systems,

<table>
<thead>
<tr>
<th>Table 4.5: Viet Nam—Investment in Generation, 2006–2010 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed capacity (MW)</td>
</tr>
<tr>
<td>-------------------------</td>
</tr>
<tr>
<td>Approved in PDP VI</td>
</tr>
<tr>
<td>Actual Investment</td>
</tr>
<tr>
<td>Ratio of Actual/Approved Investment</td>
</tr>
</tbody>
</table>

PDP VI = Power Development Plan VI, MW = megawatt.
and other resources need to be further separated and a regulatory framework is needed for ring fencing the separate entities, with established codes of conduct and confidentiality requirements. The generation companies should be audited periodically to ascertain whether they are operating independently. Rather than remaining part of a holding company structure, generating entities should become fully independent state-owned enterprises or joint stock companies as soon as possible, with private participation through equitization where feasible. In addition, the independence of the system operator must be confirmed as planned in 2015, as this is an essential prerequisite for attracting private sector capital.

Reform efforts have not created an independent generating subsector and, critically, transparency is lacking in both tariff setting and regulation. The Electricity Regulatory Authority of Viet Nam has a limited advisory role, authorized only to assist the MOIT in regulating the operation of the power market. The government retains a strong vested ownership and management interest in the sector, making independent regulation virtually impossible under current conditions. Achieving true political and economic independence of all market players, the basic requirement for competition, will require more than a virtual, functional unbundling of EVN activities.

<table>
<thead>
<tr>
<th>Project</th>
<th>Approved in Plan</th>
<th>Implementation</th>
<th>Ratio of Implemented/Approved Investment (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Quantity</td>
<td>Volume (MVA/km)</td>
<td>Quantity</td>
</tr>
<tr>
<td>500-kV Substation</td>
<td>15</td>
<td>8,400</td>
<td>9</td>
</tr>
<tr>
<td>500-kV line</td>
<td>12</td>
<td>1,339</td>
<td>6</td>
</tr>
<tr>
<td>220-kV Substation</td>
<td>87</td>
<td>19,326</td>
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</tr>
<tr>
<td>220-kV line</td>
<td>117</td>
<td>4,666</td>
<td>52</td>
</tr>
</tbody>
</table>

km = kilometer, kV = kilovolt, MVA = megavolt-ampere.

5. OUTCOMES: POWER SECTOR DEVELOPMENT IN THE REFORMING COUNTRIES

5.1. Introduction: Use of Indicators

The previous chapters discussed institutional changes in each country, and their implications for economic efficiency, transparency, and governance were discussed in general terms. This chapter focuses more narrowly on aspects of performance where the changes can be quantified on the basis of selected indicators. The trends in the indicators over time, covering periods both before and after the reform, are highlighted to assess the impact of reform. As noted in Chapter 1, each country studied undertook power sector reform as part of a larger, over-all economic recovery effort. Thus, isolating the precise impact of the power sector reform from other factors influencing its outcomes is extremely difficult. Furthermore, in two of the three cases (Sri Lanka and Viet Nam), reform has been both very recent and limited in scope.

Nonetheless, the trends in outcomes after reform provide useful information. The changes considered in this chapter include measures of supply efficiency; changes in demand; and the delivery of socioeconomic benefits, such as improved access to power and trends in environmental quality. To assess these outcomes, the report uses a set of commonly agreed and internationally accepted indicators relevant to the power sector, and presents those for which data suffice (IAEA et al. 2005).

Table 5.1 gives the indicators for which there are data and that, therefore, have been used in the analysis. The indicators reflect individual country conditions (for example, in relation to resource endowments, geography, and institutional structure) and should therefore be seen as country-specific, reflecting a country’s general conditions as well as the details of its power sector. The indicators are most useful for exploring trends within a specific country, for example after reform, rather than for cross-country comparisons. In addition, changes in several indicators need to be interpreted carefully. In particular, changing electricity intensity may be influenced strongly by changing economic structure; thus, electricity per unit of gross domestic product (GDP) will rise as the share of agriculture in GDP declines and that of industry rises. This will be independent of the sector’s efficiency in terms of technology or generation and transmission losses. Similarly, a rise in the share of renewables in generation will be a positive outcome in terms of environmental impact, but may have negative short-term effects in terms of rising tariffs and worsening measures of affordability. Nonetheless, for individual countries, it should be possible to interpret the reasons why different indicators change and thus the indicators may be applied for assessing the country’s performance.

In the following sections, the indicators are considered in light of the key reform goals in each of the three countries. The goals are assuring physical security and reliability of supply; providing adequate, affordable, and equitable service; and reducing the environmental impact of the sector.
5. Outcomes: Power Sector Development in the Reforming Countries

5.2. Developments in Georgia

5.2.1. Georgia: Economic Indicators

After the break-up of the Soviet supply system, an immediate and major concern was assuring a reliable supply of power adequate to meet demand. In the chaos that followed independence, electricity demand that was met by effective supply fell by 60%, largely as the result of general economic decline in the industrial sector, combined with internal unrest and military conflict. Since reforms began, electricity generation has increased somewhat, which translated to modest growth in consumption per capita (Figure 5.1). The downward movement of electricity use per unit of GDP from 1999 to 2007 reflects increased efficiency in the power sector and the economy’s initial major structural shift away from industry. The revival of industry since 2008 has helped stabilize the level of electricity use per unit of GDP in recent years.

Figure 5.2 shows historical electricity demand by economic sector and highlights the impact that the reduced level of industrial activity relative to the Soviet period has had on power demand.30 The residential sector’s electricity consumption

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30 Demur Chomakhidze, a former energy regulator, has been interviewed and has provided some data.

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Table 5.1: Indicators for Assessing Power Sector Reform

<table>
<thead>
<tr>
<th>Theme</th>
<th>Subtheme</th>
<th>Energy Indicator</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Dimension</td>
<td>Equity</td>
<td>SOC1</td>
<td>Share of population without electricity</td>
</tr>
<tr>
<td></td>
<td>Affordability</td>
<td>SOC2</td>
<td>Share of household income spent on electricity</td>
</tr>
<tr>
<td></td>
<td>Disparity</td>
<td>SOC3</td>
<td>Electricity use per household</td>
</tr>
<tr>
<td>Economic Dimension</td>
<td>Use and Production patterns</td>
<td>Overall use</td>
<td>Electricity per capita</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO1</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Overall electricity intensity</td>
<td>Electricity use per unit of GDP</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO2</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Supply efficiency</td>
<td>Losses in generation, transmission, distribution</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO3</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sector electricity intensity</td>
<td>Industrial electricity use to industrial value added</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO6</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO7</td>
<td>Agricultural electricity use to agricultural value added</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO8</td>
<td>Service electricity use to service value added</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO9</td>
<td>Electricity use per household</td>
</tr>
<tr>
<td>Diversification (fuel mix)</td>
<td></td>
<td>ECO11</td>
<td>Fuel shares in electricity generation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO12</td>
<td>Noncarbon share in electricity generation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO13</td>
<td>Renewable energy share in electricity generation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ECO14</td>
<td>Electricity tariffs</td>
</tr>
<tr>
<td>Security</td>
<td>Imports</td>
<td>ECO15</td>
<td>Electricity imports relative to demand</td>
</tr>
<tr>
<td>Environmental Dimension</td>
<td></td>
<td>ENV1</td>
<td>CO₂ emissions per unit of electricity</td>
</tr>
</tbody>
</table>

Note: The table’s original source applies these indicators to units of energy and, as far as possible in the country cases, the indicators are calculated per unit of electricity.

Source: IAEA et al. (2005).
Assessment of Power Sector Reforms in Asia

has exceeded that of industry since 1994, although industry’s demand has been increasing rapidly since 2008.

Figure 5.3 shows electricity intensities over time for the major sectors. All sectors’ intensities were on a downward trend from 1993 to 2007. After 2009, industry’s electricity intensity rose with the expansion of manufacturing, while the electricity intensity of services and agriculture rose only modestly. Services’ output has grown relatively rapidly after 2009, but new investments in banking and real estate, for example, required relatively low electricity inputs.

Most relevant for the analysis is the fact that, since 2002, through reform, generation capacity has been rehabilitated. This, combined with electricity

Figure 5.1: Georgia—Electricity Use per Capita and per Unit of GDP, 1990–2013

GDP = gross domestic product, kWh = kilowatt-hour.
Sources: ESCO, Energy Balances (accessed September–October 2014) and unpublished data, for electricity use; World Bank, World Development Indicators (accessed July 2014), for GDP; and National Statistics Office of Georgia (2013), for population.

Figure 5.2: Georgia—Electricity Consumption by Sector, 1990–2012 (%)

kWh = kilowatt-hour.
imports, has allowed a reliable and secure supply of power adequate to meet all demand, with some exports of surplus power (see Figure 2.8).

Efficiency has also increased in the postreform period. From 2004 to 2011, rehabilitation and improved maintenance increased the plants’ operational capacities. Accurate and complete data are not available to measure improvements in conversion efficiency for thermal plants, but sufficient information is available to state that, from 2001 to 2005, generation losses fell to 9%–4%—a major improvement over prereform estimates of losses as high as 20%.

The constancy and reliability of electricity delivered is another measure of system supply efficiency, with improvements in service generally measured as reductions in blackouts or service interruptions. Rehabilitation of the transmission network significantly decreased both of these technical inefficiencies. Transmission losses were approximately 16% in 1995, but by 2013 they were below 2%, reflecting improved management; technical conditions; system rehabilitation; and, after 2006, the transfer of the 110-kilovolt transmission lines to the distribution companies. Table 5.2 gives more detail of recent losses by type of transmission line and by area.

Figure 5.3: Georgia—Comparison of Electricity Intensities by Sector and Total, 1990–2012 (kWh/$)

Table 5.2: Georgia—Transmission and Distribution Losses, 2007–2013 (%)

<table>
<thead>
<tr>
<th>Year</th>
<th>Transmission Losses in 35–500-kV Lines</th>
<th>Distribution Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>JSC Energo-Pro Georgia</td>
</tr>
<tr>
<td>2007</td>
<td>1.9</td>
<td>28</td>
</tr>
<tr>
<td>2008</td>
<td>2.0</td>
<td>20</td>
</tr>
<tr>
<td>2009</td>
<td>1.7</td>
<td>16</td>
</tr>
<tr>
<td>2010</td>
<td>1.7</td>
<td>10</td>
</tr>
<tr>
<td>2011</td>
<td>1.9</td>
<td>10</td>
</tr>
<tr>
<td>2012</td>
<td>1.8</td>
<td>13</td>
</tr>
<tr>
<td>2013</td>
<td>2.0</td>
<td>8</td>
</tr>
</tbody>
</table>

kV = kilovolt.
Recent data on the number of blackouts show a similar marked improvement in reliability relative to a peak of inefficiencies in 2005 (Table 5.3). The rise in the incidence of blackouts in 2010 is attributed to rehabilitation work on the system that required periodic disconnections.

Despite these impressive improvements in system supply, the sector remains vulnerable in two respects. It relies heavily on a single generating technology—hydro—which is cyclical yearly and subject to drought. This in turn requires electricity imports to balance the seasonal fluctuations in hydropower generation, and gas imports to fuel the thermal generation that supplements hydropower.

Given the seasonal nature of hydro, Georgia may always have an annual export and import power cycle, sometimes as a net importer and sometimes as a net exporter. However, net imports have been falling and were close to zero in 2012. Nevertheless, the value of net electricity imports plus the value of thermal generation (which requires imported fuels) as a share of total electricity consumption remains significant at 19% in 2013. Georgia has taken steps to diversify its gas import, but reliance on a single generating technology will continue, and in fact government plans propose to increase this to 100% of hydropower generation.

Table 5.4 summarizes the efficiency gains in electricity supply since reform began. While

### Table 5.3: Georgia—Number of System Blackouts

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Blackouts</th>
<th>Partial Blackouts</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>...</td>
<td>3</td>
</tr>
<tr>
<td>2004</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>2005</td>
<td>2</td>
<td>14</td>
</tr>
<tr>
<td>2006</td>
<td>0</td>
<td>11</td>
</tr>
<tr>
<td>2007</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>2008</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2009</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>2010</td>
<td>2</td>
<td>8</td>
</tr>
<tr>
<td>2011</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>2012</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>2013</td>
<td>0</td>
<td>3</td>
</tr>
</tbody>
</table>

... = not available


### Table 5.4: Georgia—Economic Indicators of Power System Performance

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total annual electricity consumption (million KWh)</td>
<td>7,826</td>
<td>7,875</td>
<td>8,145</td>
<td>8,441</td>
<td>9,257</td>
<td>9,379</td>
<td>9,690</td>
</tr>
<tr>
<td>Annual electricity use per capita (KWh)</td>
<td>1,632</td>
<td>1,776</td>
<td>1,885</td>
<td>1,903</td>
<td>2,071</td>
<td>2,085</td>
<td>2,161</td>
</tr>
<tr>
<td>Electricity use per unit of GDP (KWh/$)</td>
<td>3.4</td>
<td>2.6</td>
<td>1.9</td>
<td>1.5</td>
<td>1.6</td>
<td>1.5</td>
<td>1.0</td>
</tr>
<tr>
<td>Transmission losses 35–500-kV. Lines (%)</td>
<td>16</td>
<td>11</td>
<td>3.8</td>
<td>1.7</td>
<td>1.9</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>Industrial electricity intensities (KWh/$)</td>
<td>3.90</td>
<td>1.21</td>
<td>0.90</td>
<td>1.34</td>
<td>1.68</td>
<td>1.48</td>
<td>...</td>
</tr>
<tr>
<td>Agricultural electricity intensities (kWh/$)</td>
<td>0.53</td>
<td>0.63</td>
<td>0.39</td>
<td>0.33</td>
<td>0.47</td>
<td>0.53</td>
<td>...</td>
</tr>
<tr>
<td>Service electricity intensities (kWh/$)</td>
<td>1.14</td>
<td>0.42</td>
<td>0.29</td>
<td>0.28</td>
<td>0.33</td>
<td>0.32</td>
<td>...</td>
</tr>
<tr>
<td>Share of Electricity Production by Thermal Power Plant (%)</td>
<td>12</td>
<td>21</td>
<td>15</td>
<td>7</td>
<td>22</td>
<td>26</td>
<td>18</td>
</tr>
<tr>
<td>Share of Electricity Production by Hydropower Plant (%)</td>
<td>88</td>
<td>79</td>
<td>85</td>
<td>93</td>
<td>78</td>
<td>74</td>
<td>82</td>
</tr>
<tr>
<td>Tariff Rates (Tbilisi) (GEL/kWh)*</td>
<td>0.05</td>
<td>0.10</td>
<td>0.12</td>
<td>0.16</td>
<td>0.16</td>
<td>0.16</td>
<td>0.16</td>
</tr>
<tr>
<td>Tariff Rates (Region) (GEL/kWh)*</td>
<td>0.05</td>
<td>0.08</td>
<td>0.08</td>
<td>0.16</td>
<td>0.16</td>
<td>0.16</td>
<td>0.16</td>
</tr>
<tr>
<td>Net electricity import dependence (%)</td>
<td>9.6</td>
<td>4.7</td>
<td>15.7</td>
<td>-15</td>
<td>-5.0</td>
<td>0.9</td>
<td>0.3</td>
</tr>
<tr>
<td>Net gas import dependence (%)</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

... = not available, GEL = lari (Georgian currency), kV = kilovolt, kWh = kilowatt-hour.

* 220/380-kV average price.

Sources: ESCO, unpublished data and Energy Balances, for electricity consumption and generation; National Statistics Office of Georgia (2013), for population; World Bank, World Development Indicators, for gross domestic product and gross value added in constant 2005 $; Demur Chomakhidze (unpublished data), GNERC, and International Energy Agency, for sector electricity consumption; GSE, GNERC–Zoia (unpublished data), and GNERC (2014), for transmission losses; GNERC, JSC Engero-Pr Georgia, and JSC Telasi for tariff rates; and ESCO Energy Balances, Lali Gogishvili (unpublished data), and International Energy Agency for import and export. (All websites accessed July–October 2014.)
not all of these gains can be ascribed directly to specific reform measures, clearly, the reforms made it possible for the sector to support and participate in the wider economic transformation of the economy.

5.2.2. Georgia: Social and Environmental Indicators

The final set of performance measures focuses on the power sector’s effectiveness at delivering the benefits of electrification in terms of customer service and environmental protection. Social benefits are traditionally measured in terms of access to electricity and the affordability of power to households, defined as the share of electricity in total household expenditure.

Almost all households in Georgia have access to commercial electricity. Only an estimated 2,000 households lack access. They are largely limited to remote mountainous villages, and some have off-grid electricity. Nonetheless, one of the Energy Policy’s goals is 100% grid access in the next few years.

Affordability does not appear to be a major issue. The absolute cost of power has risen, but average incomes have risen slightly more. Thus, the share of household income spent on electricity has fallen since 2000, averaging below 3% in 2012 (Figure 5.4). Rural and urban areas differ in both electricity use and the share of electricity expenditure in income; both were higher in urban areas during 2006–2012. However, the share of monthly electricity expenditure in the total income of urban households has been decreasing faster than that of rural households due to steeper increases in urban incomes (Table 5.5).

---

Figure 5.4: Georgia—Average Electricity Expenditure

<table>
<thead>
<tr>
<th>Year</th>
<th>Average monthly HH expenditure on Electricity ($)</th>
<th>Share of household income spent on electricity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>4.67</td>
<td>12.51</td>
</tr>
<tr>
<td>2002</td>
<td>5.24</td>
<td>12.30</td>
</tr>
<tr>
<td>2003</td>
<td>4.88</td>
<td>12.10</td>
</tr>
<tr>
<td>2004</td>
<td>5.19</td>
<td>11.90</td>
</tr>
<tr>
<td>2005</td>
<td>5.78</td>
<td>11.70</td>
</tr>
<tr>
<td>2006</td>
<td>6.40</td>
<td>11.50</td>
</tr>
<tr>
<td>2007</td>
<td>9.80</td>
<td>11.30</td>
</tr>
<tr>
<td>2008</td>
<td>12.00</td>
<td>11.10</td>
</tr>
<tr>
<td>2009</td>
<td>10.73</td>
<td>10.90</td>
</tr>
<tr>
<td>2010</td>
<td>11.14</td>
<td>10.70</td>
</tr>
<tr>
<td>2011</td>
<td>12.25</td>
<td>10.50</td>
</tr>
<tr>
<td>2012</td>
<td>12.28</td>
<td>10.30</td>
</tr>
</tbody>
</table>

HH = household.

Note: HH expenditure on electricity was computed using HH electricity consumption data from the distribution companies multiplied by the average tariff rates for 220/380-volt. GEL is converted to $ using the official period average exchange rate.

Sources: Computed using data from National Statistics Office of Georgia, for HH income; JSC Telasi and JSC Energo-Pro Georgia, for HH electricity consumption; GNERC, for electricity prices; and World Bank, World Development Indicators, for average exchange rate. (All websites accessed July–October 2014.)

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31 In terms of affordability to companies, the Georgia Business Perception Survey 2012 reports that about one-third of respondents see utility costs as a key burden and 42% of them report electricity as the most important element of the utility costs (International Finance Corporation 2012).
In terms of emissions, carbon dioxide (CO₂) from fossil fuel combustion is the major concern associated with electricity production. With the rehabilitation of major hydro stations, the share of thermal plants in total generation has been falling. Since the thermal plants have largely been rehabilitated, fuel consumption and (hence) CO₂ emissions are relatively low and have fallen during the reform period compared with the early 1990s.

Figure 5.5 gives a relative measure of power sector CO₂ emissions showing the intensity of emissions from electricity production per capita and per unit of GDP. These trends were already evident prior to the reform, with each indicator having a strongly declining trend during the economic crisis after 1990. With the rehabilitation of thermal plants and increased hydro production, the levels for all three indicators have stayed low. Table 5.6 presents the social and environmental indicators considered in the foregoing discussion.

Table 5.5: Georgia—Rural and Urban Household Expenditure on Electricity

<table>
<thead>
<tr>
<th>Expenditure and Use</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Share of Household Income Spent on Electricity</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban (%)</td>
<td>6.3</td>
<td>5.2</td>
<td>4.3</td>
<td>4.0</td>
<td>3.6</td>
<td>3.7</td>
<td>3.2</td>
</tr>
<tr>
<td>Rural (%)</td>
<td>3.3</td>
<td>3.2</td>
<td>2.9</td>
<td>2.8</td>
<td>2.9</td>
<td>2.6</td>
<td>2.3</td>
</tr>
<tr>
<td>Average Monthly Electricity Use per Household</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urban (kWh)</td>
<td>152</td>
<td>148</td>
<td>162</td>
<td>163</td>
<td>167</td>
<td>174</td>
<td>169</td>
</tr>
<tr>
<td>Rural (kWh)</td>
<td>93</td>
<td>91</td>
<td>99</td>
<td>99</td>
<td>103</td>
<td>107</td>
<td>104</td>
</tr>
</tbody>
</table>

kWh = kilowatt-hour.
Sources: Computed using data from National Statistics Office of Georgia, for household income; Telasi and Energo-Pro Georgia, for household electricity consumption; GNERC, for electricity prices; and World Bank, World Development Indicators, for the period average GEL-$ exchange rate. (All websites accessed July–October 2014.)

Figure 5.5: Georgia—CO₂ Emissions from Electricity Production

CO₂ = carbon dioxide; GDP = gross domestic product; kg-kilogram.
Sources: International Energy Agency database (accessed February 2014), for CO₂ emissions from electricity production; National Statistics of Georgia (2013), for population; and World Bank, World Development Indicators (accessed July 2014), for GDP.
Star diagrams are used to summarize and visually illustrate trends in the key indicators. For Georgia, years are selected based on identifiable milestones: 1995 to reflect the start of phase 1 of the reform, 2005 to reflect the start of phase 2, and the latest year for which data are available after phase 2.

Figure 5.6 gives results for selected economic indicators and the data used are in Appendix Table 5.1. Total electricity consumption had been restrained by the steep increases in tariff rates starting in 1998, and by the structural shift in the economy away from industry. Relative to the base year of 1995 at the start of reform, annual electricity use per capita had increased by 32% in 2013, despite a tripling of income and improved network system efficiency, as shown by the decline in transmission losses. After 1995, the electricity intensity of industry and services declined significantly relative to the base year. The structural shift away from industry brought down overall intensity. In 2005, industry showed a major fall in intensity relative to the base year in 2005, then a rise in 2012, when the intensity level was still well below the base year figure. The services sector, which has been an important driver of economic growth, is considerably less electricity intensive, and the sector’s intensity in 2012 was about 28% of its 1995 level.

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### Table 5.6: Georgia—Indicators of Socioeconomic and Environmental Outcomes

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Population without electricity (%)</td>
<td>0.11</td>
<td>0.13</td>
<td>0.14</td>
<td>0.14</td>
<td>0.14</td>
<td>0.13</td>
<td>0.13</td>
</tr>
<tr>
<td>Affordability for Households, National (% share of household income spent on electricity)</td>
<td>...</td>
<td>...</td>
<td>4.0</td>
<td>3.0</td>
<td>3.0</td>
<td>2.9</td>
<td>2.6</td>
</tr>
<tr>
<td>Average Monthly Household Electricity Use, National (kWh)</td>
<td>139</td>
<td>172</td>
<td>95</td>
<td>105</td>
<td>124</td>
<td>129</td>
<td>127</td>
</tr>
<tr>
<td>CO₂ Emissions from Electricity Production ('000 tons)</td>
<td>7,879</td>
<td>4,153</td>
<td>944</td>
<td>732</td>
<td>696</td>
<td>1,034</td>
<td>...</td>
</tr>
<tr>
<td>CO₂ Emissions per Capita from Electricity Production (ton/capita)</td>
<td>1.45</td>
<td>0.87</td>
<td>0.21</td>
<td>0.17</td>
<td>0.16</td>
<td>0.23</td>
<td>...</td>
</tr>
<tr>
<td>CO₂ Emissions from Electricity Production per Unit of GDP (kg/constant 2005$)</td>
<td>0.66</td>
<td>1.22</td>
<td>0.20</td>
<td>0.11</td>
<td>0.08</td>
<td>0.12</td>
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</tr>
</tbody>
</table>

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</tr>
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<tbody>
<tr>
<td>Affordability for Households, National (% share of household income spent on electricity)</td>
<td>...</td>
<td>...</td>
<td>4.0</td>
<td>3.0</td>
<td>3.0</td>
<td>2.9</td>
<td>2.6</td>
</tr>
<tr>
<td>Average Monthly Household Electricity Use, National (kWh)</td>
<td>139</td>
<td>172</td>
<td>95</td>
<td>105</td>
<td>124</td>
<td>129</td>
<td>127</td>
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<td>CO₂ Emissions from Electricity Production ('000 tons)</td>
<td>7,879</td>
<td>4,153</td>
<td>944</td>
<td>732</td>
<td>696</td>
<td>1,034</td>
<td>...</td>
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<tr>
<td>CO₂ Emissions per Capita from Electricity Production (ton/capita)</td>
<td>1.45</td>
<td>0.87</td>
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<td>0.17</td>
<td>0.16</td>
<td>0.23</td>
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<tr>
<td>CO₂ Emissions from Electricity Production per Unit of GDP (kg/constant 2005$)</td>
<td>0.66</td>
<td>1.22</td>
<td>0.20</td>
<td>0.11</td>
<td>0.08</td>
<td>0.12</td>
<td>...</td>
</tr>
</tbody>
</table>

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... = not available, CO₂ = carbon dioxide, GDP = gross domestic product, kWh = kilowatt-hour.

Estimation, about 45 mountain villages are without access to electricity. A household is assumed to have 3 members.

Sources: Computed using data from National Statistics Office of Georgia (2013), for population, and (n.d.), for household income; JSC Telasi, JSC Energo-Pro Georgia, World Bank (2007), for household electricity consumption; GNERC, for electricity prices; International Energy Agency (2013), for CO₂ emissions from electricity production; World Bank, World Development Indicators, for GDP and GEL-$ exchange rate. (All websites accessed July–October 2014.)

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### 5.2.3. Georgia: Summary of Reform Trends and Outcomes

5. Outcomes: Power Sector Development in the Reforming Countries

5.2.3. Georgia: Summary of Reform Trends and Outcomes

Star diagrams are used to summarize and visually illustrate trends in the key indicators. For Georgia, years are selected based on identifiable milestones: 1995 to reflect the start of phase 1 of the reform, 2005 to reflect the start of phase 2, and the latest year for which data are available after phase 2.

Figure 5.6 gives results for selected economic indicators and the data used are in Appendix Table 5.1. Total electricity consumption had been restrained by the steep increases in tariff rates starting in 1998, and by the structural shift in the economy away from industry. Relative to the base year of 1995 at the start of reform, annual electricity use per capita had increased by 32% in 2013, despite a tripling of income and improved network system efficiency, as shown by the decline in transmission losses. After 1995, the electricity intensity of industry and services declined significantly relative to the base year. The structural shift away from industry brought down overall intensity. In 2005, industry showed a major fall in intensity relative to the base year in 2005, then a rise in 2012, when the intensity level was still well below the base year figure. The services sector, which has been an important driver of economic growth, is considerably less electricity intensive, and the sector’s intensity in 2012 was about 28% of its 1995 level.

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### Figure 5.6: Georgia—Selected Economic and Relevant Indicators, Base Year = 1995

GDP = gross domestic product, GEL = lari (Georgian currency), V = volt.

Notes: The numbers are interpreted from the base year. For example, a value of 2 in 2013 means the indicator doubled from 1995 to 2013. 2012 data are used as proxy for 2013, for sectoral electricity intensities. The average tariff rates are calculated using the average tariff rates (in GEL) charged to consumers on 220/380-V lines.

Sources: Computed using data from National Statistics Office of Georgia (2013), for population, and (n.d.), for household income; JSC Telasi, JSC Energo-Pro Georgia, World Bank (2007), for household electricity consumption; GNERC, for electricity prices; International Energy Agency (2013), for CO₂ emissions from electricity production; World Bank, World Development Indicators, for GDP and GEL-$ exchange rate. (All websites accessed July–October 2014.)
The import dependence indicator has been variable primarily due to the annual variations in hydropower. The decrease in electricity and gas imports in 2013 can be attributed to the improved operational efficiency of hydro and thermal generation units resulting from the rehabilitation efforts, and the strong decline in transmission losses.

Figure 5.7 gives the equivalent diagram for social indicators. The social impact of reforms was largely felt after phase 2 of the program, as shown by pronounced movements of 2012 indicators. The increase in tariff rates did not dampen household electricity use, as average monthly household income increased more pronouncedly than electricity tariffs; thus, the indicator of average affordability of electricity improved relative to the base year. Household expenditures on electricity increased significantly in 2012 relative to the base year, with expenditures of rural households increasing more steeply than that of urban households. This can be attributed to two factors: tariff rates increased more pronouncedly in the regions than in Tbilisi, and supply has become more stable in these areas in recent years. Absence of disaggregated household income before 2006 limits the historic analysis of affordability for urban and rural households. Reforms did not affect the number of households without access to electricity, which remains at less than 1%. Data for Figure 5.7 are in Appendix Table A5.2.

Figure 5.8 and Appendix Table A5.3 show environmental trends in CO₂ emissions. From the base year, CO₂ emissions and CO₂ emissions per capita decreased in 2005, owing to the slight decline in domestic electricity production and the significant improvement in network efficiency. However, between 2005 and 2011, CO₂ emissions increased with the recovery in domestic electricity production.

**Figure 5.7: Georgia—Selected Social and Relevant Indicators, Base Year = 2001**

- Population without electricity
- Share of household income spent on electricity
- Average monthly HH expenditure on electricity, urban
- Average monthly HH expenditure on electricity, rural
- Average monthly HH income
- Tariff rates (Region)
- Tariff rates (Tbilisi)
- Electricity use/HH

**Figure 5.8: Georgia—Selected Environmental and Relevant Indicators, Base Year = 1995**

- CO₂ emissions from electricity production
- CO₂ emissions from electricity production per capita
- Share of electricity production from renewables
- CO₂ emissions from electricity production per unit of GDP

**Notes:**
- HH = household.
- The numbers are interpreted from the base year. For instance, a value of 2 in 2012 means the indicator doubled from 2001 to 2012. Tariff rates are based on tariff rates applied to consumers of 220/380 volt lines. Total population without electricity was computed using the national experts’ estimate of 3 members per HH. National experts estimate that 2,000 HHs annually had no access to electricity during 1990–2012.
- Sources: GNERC, for tariff rates; JSC Telasi and JSC Energo-Pro Georgia, for household electricity consumption; World Bank, World Development Indicators, for GEL-$ exchange rate; National Statistics Office of Georgia (n.d.), for household income, and (2013), for population; and national experts’ estimates for share of population without electricity and number of persons per household. (All websites accessed July–October 2014.)
production and, critically, the decline in the share of electricity production from renewables. At this time, natural gas-fired generation was required to complement hydropower to meet the high demand during the winter. In terms of CO₂ emissions per unit of GDP, drops in 2005 and 2011 relative to the base year were due to the change in economic structure and the modernization of production processes, as noted earlier.

5.3. Developments in Sri Lanka

5.3.1. Sri Lanka: Economic Indicators

Electricity use per capita grew rapidly from 1990 to 2013, reflecting both rising incomes and greater access to the national grid (Figure 5.9).

The electricity intensity of GDP (Figure 5.10) also rose consistently from 1996 to 2006, then declined between 2007 and 2009 and between 2011 and 2013, reflecting to some extent changes in relative intensities. The change in more recent years is likely associated with the rise in services’ share of GDP relative to that of industry, as the former is less electricity-intensive (Figures 5.11 and 5.12). Energy efficiency initiatives may also have contributed to the reduction of intensity after 2006, as government policy places a strong emphasis on energy conservation through measures such as phasing out inefficient devices and appliances and labeling energy conversion efficiencies in appliances.

Household energy intensity fell between 1990 and 1996 principally due to the lack of supply resulting from the power crises. Since 1996, the trend has been largely flat (Figure 5.13).

In the initial postreform period, losses have been reduced and efficiency improved in generation, transmission, and distribution. The Ceylon Electricity Board (CEB) has published data on system use and total system losses (Figure 5.14). By 2013, the CEB transmission and distribution losses (technical and

$33$ In Sri Lanka, agriculture is classified as part of industry for the purpose of energy accounting. Because Sri Lanka primarily uses surface irrigation, a negligible amount of electricity is used for pumping water for irrigation. Electricity used in agricultural processing, mostly of rice and tea, is included under industry.
Figure 5.10: Sri Lanka—Electricity Intensity (kWh/2005 $) and GDP (constant 2005 $ billion)

GDP = gross domestic product, kWh = kilowatt-hour.
Sources: Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance, for electricity use; World Bank, World Development Indicators, for GDP. (All websites accessed July–October 2014.)

Figure 5.11: Sri Lanka—Sectoral Composition of GDP (%)

GDP = gross domestic product.
Sources: Central Bank of Sri Lanka, Annual Report (various years).

Figure 5.12: Sri Lanka—Sector Electricity Intensities (kWh/$, constant 2005 prices)

kWh = kilowatt-hour.
Sources: Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance, for sector electricity use; World Bank, World Development Indicators, for sector gross value added. (All websites accessed July–October 2014.)
Figure 5.13: Sri Lanka—Household Electricity Intensity

![Household Electricity Intensity Chart]

kWh = kilowatt-hour.

Figure 5.14: Sri Lanka—Electricity Transmission and Distribution Losses

![Electricity Transmission and Distribution Losses Chart]

CEB = Ceylon Electricity Board, LECO = Lanka Electricity Company, T&D = transmission and distribution.

Figure 5.15: Sri Lanka—Electricity Supply (conversion and distribution) Efficiency (%)

![Electricity Supply Efficiency Chart]

commercial) had fallen to 9.5% and those of Lanka Electricity Company were down to 6.6%. With the introduction of system loss reduction programs, the efficiency of national energy supply has improved from 78% in 2000 to about 88% in 2013, with the main improvement coming since 2005 (Figure 5.15).

As a final supply security measure, the system maintains a large reserve margin of 52% in 2013, a significant increase over the margin of 30% in 2006 (Figure 5.16).

The main vulnerability of supply is in the fuel mix, although currently the sector operates without any shortages or load shedding. As explained in Chapter 3, while hydropower continues to be an important part of the generation mix, supply from hydro is vulnerable to periods of drought. The shift toward thermal power in recent years has meant that the share of renewable energy in electricity generation has decreased significantly since the mid-1990s, from over 90% in 1995 to 60% in 2013.

The volume and cost of imported oil have both continued to increase. As a result, total expenditure on oil imports in Sri Lanka has risen significantly, from $0.311 billion in 1990 to $4.895 billion in 2012 (Figure 5.17), which is about 6% of GDP. About 55% of imported oil was used for power generation in 2012, reducing the security of power supply (IRIN 2014). The CEB is building coal-fired plants as lower cost alternatives to oil-fired independent power

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Figure 5.16: Sri Lanka—Reserve Margin in the Generating System (%)


Figure 5.17: Cost of Oil Imports ($ billion)

Note: Information is for oil imports for all sectors (electricity generation, transport, industry, other users).
Source: Central Bank of Sri Lanka (various years).
As discussed in Chapter 3, the government plans to increase the use of renewable power as an additional security measure to relieve dependence on fossil fuel imports. Figure 5.18 gives the renewable energy share in grid electricity, which has been on a downward trend since 1996. In 2012, the renewables’ share of grid electricity was below 30%, but it rose again to 60% in 2013 because of the increase in hydropower generation.

In accordance with the cost-reflective tariff policy, tariff rates of all customer categories were increased in 2011 (Figure 5.19), but further adjustments have been delayed. Commercial and industrial customers experienced steeper tariff rises than residential customers in 2011, while households with low electricity consumption are exempted from the increase and pay less than the cost of supply. Prior to 2011, significant tariff hikes occurred in 2008 in an attempt to increase the CEB’s revenue and curtail its loss.\(^{35}\)

\(^{34}\) Exploration for oil and gas reserves is ongoing in the Gulf of Mannar and may lead to off-shore reserves being developed.

\(^{35}\) The CEB imposed a mandatory 30% fuel surcharge on consumers using over 90 units of electricity per month (The Sunday Times 2013).
5.3.2. Sri Lanka: Social and Environmental indicators

The electrification rate in Sri Lanka has been growing steadily since 1990, and is relatively high for the country’s income level. More than 90% of households have an active grid connection. Even though the overall level of electrification was 96% in 2013 (Figure 5.20), there were significant differences across provinces (Figure 5.21). The areas most affected by the 30 years of civil war, the Eastern and Northern provinces, had lower levels of electrification and thus were aided by postwar rehabilitation electrification programs aiming to raise the electrification level to 100% in all provinces by 2015, with a mix of grid extensions and off-grid solutions.

In terms of affordability, the average share of household income spent on electricity has changed very little since 1990 and was just under 4% in 2012. This share rose by about half a percentage point with the implementation of tariff rises between 2010 and 2012. Significantly, the share of electricity expenditures in the income of the poorest quintile of the population has been declining since 1991—down to just under 5% in 2012, from over 7% in 1990 (Figure 5.22).

Figure 5.20: Sri Lanka—Population without Electricity

![Population without Electricity Chart]

Source: Sustainable Energy Authority of Sri Lanka, Sri Lanka Energy Balance (accessed September–October 2014), for population without electricity; and Central Bank of Sri Lanka (various years), for population.

Figure 5.21: Sri Lanka—Electrification of Provinces (%)

![Electrification of Provinces Chart]

Source: Central Bank of Sri Lanka (various years) Annual Report.
In relation to environmental indicators, a major concern is CO$_2$ emissions. As the country has moved to a generating system increasingly reliant on fossil fuel, CO$_2$ emissions per capita have risen gradually. This rise is particularly noticeable after 1996, the year oil-fired independent power producers (IPPs) began operating. As of 2011, the CO$_2$ emission per capita specifically from electricity generation was 262 kilograms (Figure 5.23). This is not high by global standards, but is a 60% increase over the 164 kilograms per person in 2000. As noted in Chapter 3, the current energy policy emphasizes the need to use sustainable energy and how successful the policy will be in reversing this trend remains to be seen. CO$_2$ emissions from electricity per unit of GDP follow a broadly similar trend as the per capita figures, except that the peak in 2005 is greater than the more recent figures (Figure 5.24). CO$_2$ emissions per unit of GDP dropped in 2006 due to the increase in generation from renewable sources and the more pronounced growth of the less energy intensive service sector. The fluctuations thereafter reflect variations in hydropower generation.

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**Figure 5.22: Sri Lanka—Electricity Affordability: Household Income Spent on Electricity (%)**

![Graph showing electricity affordability over time.]

Source: Department of Census and Statistics (2013).

**Figure 5.23: Sri Lanka—CO$_2$ Emissions from Electricity Production (kg/capita)**

![Graph showing CO$_2$ emissions from electricity production over time.]

kg = kilogram.


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The average global value is 1,878 kilograms of CO$_2$ per capita. This covers CO$_2$ emission from electricity and heat production (International Energy Agency 2013).
5.3.3. Sri Lanka: Summary of Reform Trends and Outcomes

The following star diagrams are based on selected years—1991, 1996, 2002, and the latest years for which data are available (2011–2013) as reference points. The year 1991 represents the prereform period; in 1996, the private sector started to play a role as IPPs commissioned oil-fired power plants; in 2002, serious discussion of reform started; and the latest years (2011, 2012, or 2013) with available data are used as an indication of the postreform position. Figures 5.25–5.27 depict the trends in the three sets of indicators—economic, social, and environmental—for the selected years. The data on which they are based are shown below each figure, in Appendix Tables A5.4–5.6.

Electricity use per capita tripled from 1991 to 2013, reflecting greater access to grid electricity following the network’s expansion, combined with significant increases in income, which, in turn dampened the effect of higher tariff rates on electricity demand. Relative to the base year of 1991, average electricity prices in current terms had increased by 28% by 2002 and had doubled as of the latest year available. Electricity demand was further fuelled by improved supply reliability as manifested by the higher efficiency of electricity conversion and by the significant reduction in system losses.
Overall electricity intensity had increased by about one-third in 2002 relative to 1991, the base year, but by 2013 the difference from the base year was reduced to just over a quarter as the role of services in the economy further increased and after electricity efficiency and conservation measures were introduced in 2006.

Access to grid electricity has been improving throughout the period. In 2012, the share of the population without electricity had decreased by 91% from the 1991 level as a result of the successful electrification programs. Consumption of electricity per household declined slightly from the base year, which may be due to conservation measures following increases in tariffs and regulatory instruments such as appliance labeling.

With the growth of income per capita, the share of household income spent on electricity declined in 1996 and 2002 relative to 1991. Although this share increased between 2002 and 2012, when the government raised tariff rates substantially, it remained below the base year level in 2012. With electricity subsidies provided by the government, the share for the poorest 20% of households decreased more pronouncedly relative to the base year than the household average. However, as in 2012, the poor continued to spend a higher proportion of their income on electricity than did the average household.

Along with the increase in electricity consumption per capita (as noted in Figure 5.27) compared with the base year came very substantial increases in CO₂ emissions from electricity production per capita and per unit of GDP. This is explained by the decline in the shares of noncarbon and renewable energy in electricity generation with the growing share of thermal generation, which overtook hydro generation in 2000. In 2011, however, as a result of above-average rainfall, hydro's share increased. Thus, shares of noncarbon and renewable energy in electricity production rose and CO₂ emissions from electricity production per unit of GDP declined between 2002 and 2011.
5.4. Developments in Viet Nam

Under the Doi Moi program, Viet Nam has implemented several socioeconomic development plans to move from the rigidities of a centrally-planned economy to one that is more open and market-based.

As explained in Chapter 4, since these general reforms began, the country has achieved impressive growth, with GDP per capita tripling in 2 decades. Industrialization has been central to this growth. Industry, by far the most energy-intensive sector, increased its share of GDP from 25.1% in 1990 to 38.3% in 2013, resulting in major growth in demand for electricity (Figure 5.28).

5.4.1. Viet Nam: Economic Indicators

Electricity use per capita has been increasing since the late 1980s. Most of this increase occurred after 2000, with consumption per capita almost doubling from 2006 to 2013. As explained in Chapter 4, this rapid increase was only possible with the expansion of the electricity network under the National Power Development Plan VI.

Power generation has been sufficient to meet the demand since before 1990. Table 5.7 summarizes the general trends of electricity use per capita, electricity intensity, and efficiency losses, starting from 1990, before power sector reform began.

Figure 5.28: Viet Nam—Sectoral Shares of GDP, 1990–2013 (2005 $ billion)

![Sectoral Shares of GDP](image)

GDP = gross domestic product.

Table 5.7: Viet Nam—Electricity Consumption per Capita, Intensity, and System Losses

<table>
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</thead>
<tbody>
<tr>
<td>Electricity Consumption per Capita</td>
<td>kWh/capita</td>
<td>98.10</td>
<td>159.30</td>
<td>295.02</td>
<td>616.61</td>
<td>1,077.61</td>
<td>1,188.14</td>
<td>1,282.69</td>
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<tr>
<td>Electricity Intensity</td>
<td>kWh/2005 $</td>
<td>0.33</td>
<td>0.39</td>
<td>0.56</td>
<td>0.83</td>
<td>1.13</td>
<td>1.20</td>
<td>1.24</td>
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<tr>
<td>Losses*</td>
<td>% of production</td>
<td>25.40</td>
<td>21.70</td>
<td>13.77</td>
<td>11.35</td>
<td>10.14</td>
<td>8.9b</td>
<td>...</td>
</tr>
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</table>

... = not available

* Transmission and distribution losses.

Sources: Computations based on data from National Load Dispatch Centre (2014) and Viet Nam Electricity (2014), for electricity consumption; World Bank, World Development Indicators, for GDP and losses; General Statistics Office of Viet Nam, for population. (All websites accessed April–October 2014.)
The economy’s electricity intensity has grown with the increasing share of industry in GDP, at an average rate of 6% annually in the period 1990–2013 (Figure 5.29). Electricity intensity increased across the three main producing sectors (industry, agriculture, and services), but industry remains by far the most electricity-intensive sector (Table 5.8). In 2013, industry’s electricity intensity was 1.71 kilowatt-hours (kWh) per unit of value added in 2005 United States dollars, compared with agriculture at 0.11 kWh and services at 0.26 kWh.

In terms of supply security, Viet Nam is largely self-sufficient. It normally exports energy, although it did import a very small amount of power in 2011 (444 kilotons of oil equivalent). System reliability has improved with the rehabilitation and expansion of the transmission and distribution systems. Following the concerted rehabilitation program that started in 2006, system efficiency has improved and transmission and distribution losses have fallen (Table 5.9). System losses fell from 25.4% in 1990 to 10.1% in 2008. In 2010 and 2011, system losses rose as regional low-voltage rural systems were integrated into the national grid. An estimated figure for 2012 system losses (8.9%) further indicates successful rehabilitation of the grid.

5.4.2. Viet Nam: Social and Environmental Indicators

In relation to access, increased electrification has been a key policy objective for many years. In fact, the largest increase in access to grid power (from 50% to 88% of the population) occurred during 1995–2004, before the current power sector reforms started. This was a period when the Electricity of Viet Nam piloted electrification of rural communes and the government set clear electrification targets. Progress has been continued post-2005, and by 2012 an estimated 99.4% of the communes and 97.2% of households had been connected to the grid. These increases reflect significant government investment in generation, transmission, and distribution (Figure 5.30).

Currently, about 1 million people, primarily in the mountainous northern regions, are still without access to electricity. New investment is being proposed for the national grid and for distributed power (small and micro hydro, solar, wind, and diesel) to supply electricity to rural mountainous and island areas. While access levels may not have changed dramatically since the electricity reform began, average absolute levels of electricity use of

Figure 5.29: Viet Nam—Electricity Intensity by Sector, 1990–2013 (kWh/2005 $)

<table>
<thead>
<tr>
<th>Year</th>
<th>Industry kWh</th>
<th>Agriculture kWh</th>
<th>Services kWh</th>
<th>Whole economy kWh</th>
</tr>
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<tbody>
<tr>
<td>1990</td>
<td>0.20</td>
<td>0.40</td>
<td>0.60</td>
<td>0.80</td>
</tr>
<tr>
<td>1991</td>
<td>0.25</td>
<td>0.45</td>
<td>0.70</td>
<td>0.95</td>
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<tr>
<td>1992</td>
<td>0.30</td>
<td>0.50</td>
<td>0.75</td>
<td>1.00</td>
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<tr>
<td>1993</td>
<td>0.35</td>
<td>0.55</td>
<td>0.80</td>
<td>1.05</td>
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<tr>
<td>1994</td>
<td>0.40</td>
<td>0.60</td>
<td>0.85</td>
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<td>1995</td>
<td>0.45</td>
<td>0.65</td>
<td>0.90</td>
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<td>1996</td>
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<td>2004</td>
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<td>2005</td>
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<td>2006</td>
<td>1.00</td>
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<td>2007</td>
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kWh = kilowatt-hour.
Notes: Services’ electricity use includes “Others.” Whole economy includes the residential sector.
Sources: Computations based on data from the National Load Dispatch Centre (2014) and Viet Nam Electricity (2014), for electricity consumption; World Bank, World Development Indicators, for GDP and sector value added (accessed April–October 2014).
households have grown rapidly with rising income, from 5,369 gigawatt-hours (GWh) in 1995 to 38,421 GWh in 2012 and 41,749 GWh in 2013.

Affordability as measured by the percentage of household income spent on electricity, has worsened after reform, but only modestly. During 2002–2012, average household electricity expenditures increased more than sixfold, while household income grew almost five times resulting in a modest rise in the ratio of electricity expenditure to income. During this period, average expenditure on electricity has been 3%–4% of income (Table 5.10). The disparity in this ratio between income groups is also relatively low. In 2012, the poorest 20% of the households spent about 4.7% of their monthly income on power while the richest 20% spent 3.7% (Table 5.11). When the changes are indexed to 2002 as the base year, there is a regressive shift with the share of expenditure rising more for the poorest.38

Households appear to be favored by cross-subsidies between customers. Despite the higher costs of more dispersed distribution, households

---

37 Data available for this indicator start in 2002.
38 These figures are not very precise because the household survey data (General Statistics Office of Viet Nam 2013) on which they are based combines expenditure on electricity with that on housing, sanitation, and water. Further, the data are likely to omit any receipt of cash transfers to cover electricity costs by the poorest households.
pay relatively lower charges than commercial users, even though the latter use high-voltage power and bulk deliveries that cost less to supply. In 2011, average commercial users paid approximately 50% more per kilowatt-hour than average households (Poch and Tuy 2012).

CO₂ emissions increased rapidly in recent years due to the shift toward coal-fired power plants. In 2009, total CO₂ emissions in Viet Nam were estimated to be about 150.9 million tons. Of this amount, the energy sector is estimated to have contributed 52.7 million tons of CO₂ (35%), mostly from thermal coal- and gas-fired plants. Aggregate CO₂ emissions from electricity production per capita grew by 10% annually during 1990–2011 and the emissions intensity of GDP grew at 4% annually (Figures 5.31 and 5.32).

### 5.4.3. Viet Nam: Summary of Reform Trends and Outcomes

For Viet Nam, economic and environmental indicators are shown for 1995 (the year when Electricity of Viet Nam was created) as the base year. Other years used are 2000 (the year IPPs were introduced); 2006 (when the Power Sector Reform Road Map was approved); and the latest year available (2011–2013, to reflect the position after the initial moves toward creating a competitive generation market).

Electricity use per capita had increased by more than eight times in 2013 relative to the base year of 1995. The increase was driven by the growth of income combined with enhanced sustainability of supply; improved energy supply efficiency, as shown by the decline in transmission and distribution losses; and widespread electrification. In addition, the relatively low tariff rates have encouraged the intensive use of electricity among all users including households.

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**Table 5.10: Viet Nam—Household Monthly per Capita Expenditure on Electricity and Income, 2002–2012**

<table>
<thead>
<tr>
<th>Year</th>
<th>Expenditure on Electricity* (current prices, D ‘000)</th>
<th>Income (current prices, D ‘000)</th>
<th>Expenditure on Electricity (% of Income)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>11.17</td>
<td>356.08</td>
<td>3.14</td>
</tr>
<tr>
<td>2004</td>
<td>14.87</td>
<td>484.38</td>
<td>3.07</td>
</tr>
<tr>
<td>2006</td>
<td>19.10</td>
<td>636.50</td>
<td>3.00</td>
</tr>
<tr>
<td>2008</td>
<td>27.60</td>
<td>995.20</td>
<td>2.77</td>
</tr>
<tr>
<td>2010</td>
<td>50.00</td>
<td>1,387.10</td>
<td>3.60</td>
</tr>
<tr>
<td>2012</td>
<td>81.00</td>
<td>1,999.80</td>
<td>4.05</td>
</tr>
</tbody>
</table>

* Electricity expenditure is combined with housing, sanitation, and water. Source: General Statistics Office of Viet Nam (2013).
Table 5.11: Viet Nam—Household Monthly per Capita Expenditure on Electricity by Income Group, 2002–2012 (% of income)

<table>
<thead>
<tr>
<th>Year</th>
<th>Quintile 1</th>
<th>Quintile 2</th>
<th>Quintile 3</th>
<th>Quintile 4</th>
<th>Quintile 5</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>2.64</td>
<td>2.74</td>
<td>2.88</td>
<td>3.10</td>
<td>3.37</td>
<td>3.14</td>
</tr>
<tr>
<td>2004</td>
<td>2.91</td>
<td>2.75</td>
<td>2.87</td>
<td>3.02</td>
<td>3.23</td>
<td>3.07</td>
</tr>
<tr>
<td>2006</td>
<td>2.88</td>
<td>2.67</td>
<td>2.81</td>
<td>3.21</td>
<td>3.04</td>
<td>3.00</td>
</tr>
<tr>
<td>2008</td>
<td>2.91</td>
<td>2.77</td>
<td>2.59</td>
<td>2.92</td>
<td>2.75</td>
<td>2.77</td>
</tr>
<tr>
<td>2010</td>
<td>3.25</td>
<td>3.59</td>
<td>3.20</td>
<td>3.62</td>
<td>3.78</td>
<td>3.60</td>
</tr>
<tr>
<td>2012</td>
<td>4.69</td>
<td>4.67</td>
<td>4.20</td>
<td>4.32</td>
<td>3.66</td>
<td>4.05</td>
</tr>
</tbody>
</table>

Note: Electricity expenditure is combined with housing, sanitation, and water. Quintile 1 is the poorest and quintile 5 is the richest.

Figure 5.31: Viet Nam—CO₂ Emissions from Electricity Production (kg/capita)

CO₂ = carbon dioxide, kg - kilogram.
Source: Computed based on data from the General Statistics Office of Viet Nam, for population; and International Energy Agency (2013), for CO₂ emissions. (All websites accessed February–October 2014.)

Figure 5.32: Viet Nam—CO₂ Emissions from Electricity Production (kg/unit of GDP in 2005 $)

CO₂ = carbon dioxide, GDP = gross domestic product, kg = kilogram.
Source: Computed based on data from the World Bank, World Development Indicators, for GDP; and International Energy Agency (2013), for CO₂ emissions. (All websites accessed February–October 2014.)
By 2013, electricity intensity had grown threefold relative to 1995 for industry and agriculture and almost threefold for services. Hence, electricity intensity has generally increased in the economy, although intensity levels are far higher in industry (Figure 5.33 and Appendix Table A5.7).

The diagram for social analysis (Figure 5.34) starts with the year 2002 because data on electricity affordability prior to that year are limited. Appendix Table A5.8 presents the relevant data for this figure in index form. Lines for access to electricity moved only modestly because electrification rates had improved significantly prior to 2002. During the period, the affordability indicator deteriorated relative to the base year of 2002, especially since reforms began in 2006. However, relative to 2002, the share of income that the poorest 20% spent on electricity has risen more than the share spent by all of households.

### Figure 5.33: Viet Nam—Selected Economic and Relevant Indicators, Base Year = 1995

- **Electricity use per capita**: The graph shows the increase in electricity use per capita from 1995 to 2013, with notable growth in 2000 and 2006.
- **GDP per capita**: The data indicates an increase in GDP per capita over the years.
- **T&D losses**: There has been a decrease in T&D losses from 1995 to 2013.

### Figure 5.34: Viet Nam—Selected Social and Relevant Indicators, Base Year = 2002

- **Access to electricity**: The figure shows the percentage of households with access to electricity from 2002 to 2012. The access rate has increased over time.
- **Income per capita**: The graph illustrates the changes in household income per capita from 2002 to 2012.

### Figure 5.35: Viet Nam—Selected Environmental and Relevant Indicators, Base Year = 1995

- **CO2 per GDP**: The data indicates a decrease in CO2 emissions per GDP from 1995 to 2011.
- **Electricity use per capita**: There has been a consistent increase in electricity use per capita from 1995 to 2011.

**Note**: The numbers are interpreted from the base year. For example, a value of 2 in 2013 means the indicator doubled from the base year to 2013.

**Sources**: Computed based on data from Viet Nam Electricity (2013) for access to electricity in 1990–2011, General Directorate of Energy (2013) for access to electricity in 2012; Viet Nam Electricity (2014) and National Load Dispatch Centre (2014) for household electricity consumption; and General Statistics Office of Viet Nam (n.d.) for affordability and income per capita.

**Notes on Data**:
- **GDP** = gross domestic product, **T&D** = transmission and distribution.
- **Intensity** refers to energy consumption relative to economic output.

**Sources**:
- Computed based on data from the National Load Dispatch Centre (2014) and Viet Nam Electricity (2014), for electricity consumption and generation; General Statistics Office of Viet Nam (n.d.), for population; and World Bank, World Development Indicators, for GDP. (All websites accessed February–October 2014.)
Economic development in Viet Nam has negatively affected its environment, despite improved efficiency of transmission and distribution lines. Relative to 1995, CO₂ emissions per unit of GDP increased by 84% in 2000, and had more than tripled by 2011. CO₂ emissions per capita grew even more rapidly in 2006, to five times the 1995 level and then to about eight times the base year level in 2011. As already noted, the shift to gas- and coal-fired power generation has driven this process, with the share of renewables in total generation in 2011 only about half that in 1995 (Figure 5.35 and Appendix Table A5.9).

5.5. Summary

Power sector reform in all three countries is a continuing process. As noted, transparency, economic efficiency, regulation, and sector management still need improving. Nonetheless, progress has been made in all three case study countries. The broad picture that emerges from this experience is that each country’s power system was expanded to ensure that the rising demand created by income growth could be met without rationing power. Transmission and distribution losses were reduced significantly, reflecting improved technical efficiency. In two of the three countries, the electricity intensity of overall production has increased with industrialization, and industry has increased its share of GDP. Georgia is in a different category because, relative to the Soviet period, Georgia has deindustrialized and industry now has a much smaller share of GDP than prior to 1990. In terms of security of supply, Georgia is also the most vulnerable to fluctuations in international markets due to the need to balance shortfalls in generation from hydro sources with imports and to the continued need to import gas for its thermal plants, although Sri Lanka also relies on oil imports to fuel thermal generation.

In social terms, electrification rates are high in all countries, even in Sri Lanka and Viet Nam at their income levels. In terms of affordability (the share of income spent on electricity) for average households, Georgia has the cheapest power, but the figures are not directly comparable across the three countries. For example, the data for Viet Nam include expenditure on items other than electricity. Clearly, however, reform has not been associated with a major rise of household electricity costs in average income, and, in Sri Lanka and Viet Nam, where the data are available, reform has not been associated with a significant rise in the share of electricity cost in the income of the poorest 20% of households. The share of electricity expenditure in the income of the poor has risen marginally in Viet Nam in recent years, but has fallen in Sri Lanka.

Finally, changes in the structure of electricity generation in each of the three countries have affected its impact on the environment. Greenhouse gas emissions per unit of GDP, for example, in Georgia have fallen since the 1990s with the heavy reliance on hydro power. In Sri Lanka and Viet Nam, however the generation mix has shifted away from renewables. Consequently, emissions per capita and per unit of GDP have risen since the 1990s, markedly in the case of Viet Nam.

However, progress in transforming the power sector in these countries might have been easier if the preconditions necessary for economic reform had been better established. The next chapter describes briefly some of the differences between the power sector reform process in developed and developing countries, hopefully providing insights into possible next steps.
Appendix: Data for Star Diagrams

Table A5.1: Georgia—Selected Economic and Relevant Indicators, Base Year = 1995

<table>
<thead>
<tr>
<th>Indicators</th>
<th>1995</th>
<th>2005</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Electricity Use per Capita</td>
<td>1.00</td>
<td>1.15</td>
<td>1.32</td>
</tr>
<tr>
<td>Import Dependence</td>
<td>1.00</td>
<td>1.63</td>
<td>0.04</td>
</tr>
<tr>
<td>Transmission Losses</td>
<td>1.00</td>
<td>0.24</td>
<td>0.12</td>
</tr>
<tr>
<td>Overall Intensity</td>
<td>1.00</td>
<td>0.55</td>
<td>0.43</td>
</tr>
<tr>
<td>Electricity intensity: Services</td>
<td>1.00</td>
<td>0.25</td>
<td>0.28</td>
</tr>
<tr>
<td>Electricity intensity: Industry</td>
<td>1.00</td>
<td>0.23</td>
<td>0.38</td>
</tr>
<tr>
<td>Electricity intensity: Agriculture</td>
<td>1.00</td>
<td>0.73</td>
<td>1.01</td>
</tr>
<tr>
<td>GDP per Capita</td>
<td>1.00</td>
<td>2.05</td>
<td>3.10</td>
</tr>
<tr>
<td>Average Tariff Rates</td>
<td>1.00</td>
<td>2.10</td>
<td>3.56</td>
</tr>
</tbody>
</table>

GDP = gross domestic product, GEL = lari (Georgian currency), V = volt.
Notes: The numbers are interpreted from the base year. For example, a value of 2 in 2013 means the indicator doubled from 1995 to 2013.
*2012 data are used as proxy for 2013, for sector electricity intensities.
-The index is calculated using the average tariff rates (in GEL) charged to consumers on 220/380-V lines.
Source: Computed using data from ESCO (unpublished data and Energy Balance), for electricity use; GNERC, Demur Chomakhidze (unpublished data), and International Energy Agency database, for import and export; GSE, GNERC–Zoia, and GNERC (2014), for transmission losses; GNERC, for tariff rates; National Statistics Office of Georgia (2011), for population; and World Bank, World Development Indicators, for GDP and sector gross value added. (All websites accessed July–October 2014.)

Table A5.2: Georgia—Selected Social and Relevant Indicators, Base Year = 2001

<table>
<thead>
<tr>
<th>Indicators</th>
<th>2001</th>
<th>2005</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Population without Electricity</td>
<td>1.00</td>
<td>1.02</td>
<td>0.98</td>
</tr>
<tr>
<td>Share of HH Income Spent on Electricity</td>
<td>1.00</td>
<td>0.75</td>
<td>0.64</td>
</tr>
<tr>
<td>Average Monthly HH Expenditure on Electricity: Urban</td>
<td>1.00</td>
<td>1.22</td>
<td>2.13</td>
</tr>
<tr>
<td>Average Monthly HH Expenditure on Electricity: Rural</td>
<td>1.00</td>
<td>1.26</td>
<td>3.35</td>
</tr>
<tr>
<td>Average Monthly HH Income</td>
<td>1.00</td>
<td>1.24</td>
<td>2.63</td>
</tr>
<tr>
<td>Tariff Rates: Regions</td>
<td>1.00</td>
<td>1.03</td>
<td>2.00</td>
</tr>
<tr>
<td>Tariff Rates: Tbilisi</td>
<td>1.00</td>
<td>0.98</td>
<td>1.29</td>
</tr>
<tr>
<td>Electricity Use/HH</td>
<td>1.00</td>
<td>1.09</td>
<td>1.33</td>
</tr>
</tbody>
</table>

HH = household.
Note: The numbers are interpreted from the base year. For example, a value of 2 in 2012 means the indicator doubled from 2001 to 2013.
* Based on tariff rates applied to consumers of 220/380 volt lines.
* Total population without electricity was computed using the national experts’ estimate of 3 members per HH. National experts estimate that 2,000 HHs annually had no access to electricity during 1990–2012.
Sources: GNERC, for tariff rates; JSC Telasi and JSC Energo-Pro Georgia, for household electricity consumption; World Bank, World Development Indicators, for GEL-$ exchange rate; National Statistics Office of Georgia (n.d.), for household income, and (2013), for population; and national experts’ estimates for share of population without electricity and number of persons per household. (All websites accessed July–October 2014.)
### Table A5.3: Georgia—Selected Environmental and Relevant Indicators, Base Year = 1995

<table>
<thead>
<tr>
<th>Indicators</th>
<th>1995</th>
<th>2005</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Emissions from Electricity Production</td>
<td>1.00</td>
<td>0.18</td>
<td>0.25</td>
</tr>
<tr>
<td>CO₂ Emissions from Electricity Production per Capita</td>
<td>1.00</td>
<td>0.20</td>
<td>0.27</td>
</tr>
<tr>
<td>CO₂ Emissions from Electricity Production per unit of GDP</td>
<td>1.00</td>
<td>0.09</td>
<td>0.10</td>
</tr>
<tr>
<td>Share of Electricity Production from Renewables</td>
<td>1.00</td>
<td>0.97</td>
<td>0.89</td>
</tr>
<tr>
<td>Domestic Electricity Generation</td>
<td>1.00</td>
<td>0.97</td>
<td>1.43</td>
</tr>
</tbody>
</table>

CO₂ = carbon dioxide, GDP = gross domestic product.
Note: The numbers are interpreted from the base year. For example, a value of 2 in 2011 means the indicator doubled from 1995 to 2011.

### Table A5.4: Sri Lanka—Selected Economic and Relevant Indicators, Base Year = 1991

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Use per capita</td>
<td>1.00</td>
<td>1.36</td>
<td>2.03</td>
<td>3.46</td>
</tr>
<tr>
<td>Overall Electricity Intensity</td>
<td>1.00</td>
<td>1.12</td>
<td>1.37</td>
<td>1.27</td>
</tr>
<tr>
<td>Efficiency of Electricity Conversion and Distribution</td>
<td>1.00</td>
<td>1.08</td>
<td>1.06</td>
<td>1.16</td>
</tr>
<tr>
<td>T&amp;D Loss</td>
<td>1.00</td>
<td>0.74</td>
<td>0.79</td>
<td>0.51</td>
</tr>
<tr>
<td>Industrial and Agricultural Electricity Intensity</td>
<td>1.00</td>
<td>1.08</td>
<td>1.29</td>
<td>1.06</td>
</tr>
<tr>
<td>Commercial and Services Electricity Intensity</td>
<td>1.00</td>
<td>0.92</td>
<td>1.07</td>
<td>1.37</td>
</tr>
<tr>
<td>Average electricity tariff</td>
<td>1.00</td>
<td>1.24</td>
<td>1.28</td>
<td>2.31</td>
</tr>
<tr>
<td>GDP per Capita</td>
<td>1.00</td>
<td>1.21</td>
<td>1.48</td>
<td>2.74</td>
</tr>
</tbody>
</table>

GDP = gross domestic product, T&D = transmission and distribution.
Notes: The numbers are interpreted from the base year. For example, a value of 2 in 2013 means the indicator doubled from 1991 to 2013.
* Used 2010 data as proxy.
Sources: Computations based on data from Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance, for electricity data; Ceylon Electricity Board (various years), for electricity tariff; World Bank, World Development Indicators, for GDP and sector gross value added; Central Bank of Sri Lanka (various years), for population. (All websites accessed July–October 2014.)

### Table A5.5: Sri Lanka—Selected Social and Relevant Indicators, Base Year = 1991

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Share of Population without Electricity</td>
<td>1.00</td>
<td>0.79</td>
<td>0.53</td>
<td>0.09</td>
</tr>
<tr>
<td>Share of Household Income Spent on Electricity: All</td>
<td>1.00</td>
<td>0.90</td>
<td>0.85</td>
<td>0.92</td>
</tr>
<tr>
<td>Share of Household Income Spent on Electricity: Poorest 20%</td>
<td>1.00</td>
<td>0.90</td>
<td>0.85</td>
<td>0.67</td>
</tr>
<tr>
<td>Electricity Tariff: Domestic Consumers</td>
<td>1.00</td>
<td>0.94</td>
<td>1.08</td>
<td>1.94</td>
</tr>
<tr>
<td>Electricity Use per Household</td>
<td>1.00</td>
<td>0.80</td>
<td>0.82</td>
<td>0.90</td>
</tr>
</tbody>
</table>

Note: The numbers are interpreted from the base year. For instance, a value of 2 in 2012 means the indicator doubled from 1991 to 2012.
Sources: Computations based on data from Sri Lanka Sustainable Energy Authority, Sri Lanka Energy Balance, for electricity data; Ceylon Electricity Board (various years), for tariffs; Sri Lanka Department of Census and Statistics (2013), for household data; Central Bank of Sri Lanka (various years), for population. (All websites accessed July–October 2014.)
5. Outcomes: Power Sector Development in the Reforming Countries

Table A5.6: Sri Lanka: Selected Environmental and Relevant Indicators, Base Year = 1991

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Emissions from Electricity Production per Capita</td>
<td>1.00</td>
<td>5.36</td>
<td>16.48</td>
<td>24.49</td>
</tr>
<tr>
<td>CO₂ Emissions from Electricity Production per Unit of GDP</td>
<td>1.00</td>
<td>4.41</td>
<td>11.10</td>
<td>10.39</td>
</tr>
<tr>
<td>Oil Sources (% of total generation)</td>
<td>1.00</td>
<td>3.65</td>
<td>8.01</td>
<td>7.69</td>
</tr>
<tr>
<td>Hydroelectric sources (% of total generation)</td>
<td>1.00</td>
<td>0.78</td>
<td>0.41</td>
<td>0.44</td>
</tr>
<tr>
<td>Renewable Energy Share in Electricity (Hydro + NCRE)</td>
<td>1.00</td>
<td>0.78</td>
<td>0.42</td>
<td>0.44</td>
</tr>
<tr>
<td>Electricity Use per Capita</td>
<td>1.00</td>
<td>1.36</td>
<td>2.03</td>
<td>3.22</td>
</tr>
</tbody>
</table>

CO₂ = carbon dioxide, GDP = gross domestic product, NCRE = nonconventional renewable energy.
Note: The numbers are interpreted from the base year. For example, a value of 2 in 2011 means the indicator doubled from 1991 to 2011.
Sources: International Energy Agency (2013), for CO₂ emissions; Sri Lanka Sustainable Energy Authority, for electricity data; Central Bank of Sri Lanka (various years), for population; World Bank, World Development Indicators, for GDP. (All websites accessed July–October 2014.)

Table A5.7: Viet Nam—Selected Economic and Relevant Indicators, Base Year = 1995

<table>
<thead>
<tr>
<th>Indicators</th>
<th>1995</th>
<th>2000</th>
<th>2006</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Use per Capita</td>
<td>1.00</td>
<td>1.85</td>
<td>3.87</td>
<td>8.05</td>
</tr>
<tr>
<td>Intensity: Overall</td>
<td>1.00</td>
<td>1.43</td>
<td>2.13</td>
<td>3.18</td>
</tr>
<tr>
<td>Intensity: Industry</td>
<td>1.00</td>
<td>1.19</td>
<td>1.95</td>
<td>3.23</td>
</tr>
<tr>
<td>Intensity: Agriculture</td>
<td>1.00</td>
<td>1.43</td>
<td>1.48</td>
<td>3.23</td>
</tr>
<tr>
<td>Intensity: Services</td>
<td>1.00</td>
<td>1.47</td>
<td>1.77</td>
<td>2.76</td>
</tr>
<tr>
<td>T&amp;D Losses</td>
<td>1.00</td>
<td>0.63</td>
<td>0.52</td>
<td>0.41</td>
</tr>
<tr>
<td>GDP per Capita</td>
<td>1.00</td>
<td>1.30</td>
<td>1.88</td>
<td>2.50</td>
</tr>
</tbody>
</table>

GDP = gross domestic product, T&D = transmission and distribution.
Note: The numbers are interpreted from the base year. For example, a value of 2 in 2013 means the indicator doubled from the base year to 2013.
Source: Computed based on data from National Load Dispatch Centre (2014) and Viet Nam Electricity (2014), for electricity use; Viet Nam Electricity (2014) and National Power Transmission Corporation (2014), for losses; General Statistics Office of Viet Nam, for population; and World Bank, World Development Indicators, for GDP. (All websites accessed February–October 2014.)

Table A5.8: Viet Nam—Selected Social and Relevant Indicators, Base Year = 2002

<table>
<thead>
<tr>
<th>Indicators</th>
<th>2002</th>
<th>2006</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Access to Electricity</td>
<td>1.00</td>
<td>1.16</td>
<td>1.23</td>
</tr>
<tr>
<td>Share of Household Income Spent on Electricity (All)</td>
<td>1.00</td>
<td>0.96</td>
<td>1.29</td>
</tr>
<tr>
<td>Share of Household Income Spent on Electricity (Richest 20%)</td>
<td>1.00</td>
<td>0.90</td>
<td>1.17</td>
</tr>
<tr>
<td>Share of Household Income Spent on Electricity (Poorest 20%)</td>
<td>1.00</td>
<td>1.09</td>
<td>1.50</td>
</tr>
<tr>
<td>Income per Capita (Richest 20%)</td>
<td>1.00</td>
<td>1.77</td>
<td>5.48</td>
</tr>
<tr>
<td>Income per Capita (Poorest 20%)</td>
<td>1.00</td>
<td>1.71</td>
<td>4.75</td>
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<tr>
<td>Household Electricity Consumption</td>
<td>1.00</td>
<td>1.54</td>
<td>2.68</td>
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</table>

<table>
<thead>
<tr>
<th>Indicators</th>
<th>1995</th>
<th>2000</th>
<th>2006</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ per GDP</td>
<td>1.00</td>
<td>1.84</td>
<td>2.84</td>
<td>3.39</td>
</tr>
<tr>
<td>CO₂ per Capita</td>
<td>1.00</td>
<td>2.38</td>
<td>5.16</td>
<td>7.90</td>
</tr>
<tr>
<td>Electricity Use per Capita</td>
<td>1.00</td>
<td>1.85</td>
<td>3.87</td>
<td>6.76</td>
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<tr>
<td>Share of Renewables to Total Generation</td>
<td>1.00</td>
<td>0.75</td>
<td>0.47</td>
<td>0.55</td>
</tr>
<tr>
<td>Overall Intensity</td>
<td>1.00</td>
<td>1.43</td>
<td>2.13</td>
<td>2.90</td>
</tr>
</tbody>
</table>

CO₂ = carbon dioxide, GDP = gross domestic product.
Sources: Computed based on data from National Load Dispatch Centre (2014) and Viet Nam Electricity (2014), for electricity consumption and generation; General Statistics Office of Viet Nam (n.d.), for population; and World Bank, World Development Indicators, for GDP. (All websites accessed February–October 2014.)
6. CONCLUSIONS AND LESSONS LEARNED—POWER SECTOR REFORMS, THE WAYS FORWARD

Reform of the electricity sectors in all three study countries—Georgia, Sri Lanka, and Viet Nam—has been a relatively slow and partial process with political and technical obstacles. To a certain extent, the slow process gives a country the advantage of time to evaluate the suitability of the reforms to the country’s specific and unique circumstances and to make adjustments accordingly. Stakeholders can also come to terms and harmonize their respective goals with the ensuing changes. On the other hand, the vested interests in the sector, consumer sensitivities, relatively small market size, and difficulties of attracting private finance have combined to restrict achievements. In all cases, progress with reform has not kept to the original road maps and the timing of change has been affected by political decisions. Nonetheless, there has been progress. System capacity has expanded, system losses have been reduced, and power use per capita has grown significantly. Drawing on international experience, particularly in the members of the Organisation for Economic Co-operation and Development (OECD), this chapter considers some of the issues that the study countries and similar economies continue to face in realizing reform programs’ goals and attracting new investment. The discussion focuses particularly on sources of finance, ownership structure, pricing, regulation, security of supply, and long-term planning.

A major goal of the reform effort in the three study countries has been to assure power supply that is reliable and adequate to meet all demand. This means securing sufficient financing for system maintenance, improvement, and expansion. One of the major impediments to achieving the goal in all three countries has been the utilities’ inability to develop internal financial resources to meet their capital investment requirements or to impart to private investors confidence to increase their investments in the sector. The inability to generate internal financing has been compounded by limited public resources to finance the power sector, resulting in huge power sector debts. The root causes lie in the inefficient pricing of power, and in poor governance. Off-loading power sector debt might initially help to reduce the cost of electricity, but unless power is consistently priced to cover all costs plus profit for investment, the system will continue to incur debt and will not be financially sustainable. Reform should not be expected to produce cheaper power, but power that is efficiently priced. Experience has shown that financial and economic viability as well as regulatory reform need to precede industry restructuring. Where this sequence is reversed, the long-run effects of reforms and restructuring will be disappointing.

6.1. Financing New Investment

In most countries, financing system expansion to meet the growing demand for electricity is likely to require more capital than the state’s resources can supply, given other demands on public funds. OECD countries have a well-developed domestic capital market for raising money through the sale of bonds and shares, and a variety of loans and financial instruments are available to provide funding. But in countries such as the three considered here, which do not have a well-developed domestic capital market, access to domestic financing is a problem and foreign investment is likely to be needed, at least initially.
Historically, all three governments financed the capital requirements of their own power systems, supplemented by multilateral development bank and bilateral loans. However, in each case at the time of reform, government funding for the sector was exhausted and the industry was not self-sustaining. Severe financial problems arose from a mismatch between the cost and price of electricity, largely due to politically induced administrative inefficiencies. The funds to rehabilitate, maintain, and expand the systems were lacking and the financial difficulties served as a deterrent to private investors. All three countries still lack developed local capital markets that can provide long-term bond or equity finance, and hence they rely heavily on combinations of aid funding, multinational bank loans, and foreign investment, which may result in some stakeholders lacking commitment to and a sense of ownership of the expanded power systems.

Nonetheless, since the start of reform in the three countries, some foreign aid funding, foreign investment, and even national private investment have been forthcoming. In Sri Lanka, small power producers have been financed with commercial loans from private local banks. In Georgia, the government has successfully secured donor aid that greatly facilitated the flow of private foreign investment and especially foreign management into the power sector. The sale of the distribution company Telasi to the American company AES, discussed in Chapter 2, radically improved the country’s distribution and transmission system. Georgia also drew on the expertise of OECD-based companies to manage parts of its transmission and dispatch systems and its wholesale electricity market, with generally positive results. All three countries have used independent power producers (IPPs), particularly in thermal generation, to introduce some private power in generation.

Several mechanisms are extant for introducing private foreign investment in joint ventures. In the build-operate-transfer (BOT) model for power plant construction, companies build, sometimes operate, and eventually transfer the plant to local authorities. BOT plants have been built in Viet Nam, for example, as well as in some OECD countries, notably Mexico and Turkey. This arrangement provides capacity but BOT plants operate under negotiated conditions and do not generally compete with other generators. The build-own-operate model allows the investors to keep their investments at the end of the project period. A third possibility that is more conducive to developing a domestic capital market is to sell shares domestically in the completed plant at the end of the project period. This scheme is applicable to both BOT and build-own-operate plants. Power investment has historically stimulated the development of local capital markets and could do so in these three cases.39

International experience suggests that to attract private sector funding to the electricity sector, several items are important to investors: ownership, industry structure, cost and allocation of risk, regulatory pricing, and political neutrality.

6.2. Ownership and Market Structure

To varying degrees, each of the three countries wishes to reduce the role of government, although international experience clearly indicates that there is no unique path for doing so. OECD countries show a broad spectrum of ownership patterns, ranging from a single fully state-owned utility in France (as in Sri Lanka), to a fragmented system of private companies in the United States, with varying combinations in between. New Zealand, Norway, and Sweden chose the route of corporatization as has been done in both Georgia and Viet Nam. There is nothing wrong with government owning a share of a company provided it can be run effectively and in fact this is a way for society to share in the benefits of greater competition and industry profits. In this respect the three countries are not unlike some OECD countries.

39 In the United Kingdom and the United States, for example, the sale to foreigners of bonds and shares in infrastructure development (railroads, canals, and power generation) formed the basis for the domestic capital market. The Republic of Korea used its electricity assets to develop its own domestic capital markets and eventually was able to list the national utility KEPCO on the New York Stock Exchange.
As with ownership, industry structure also varies internationally. All three countries have taken steps to restructure their generation subsector, although market-driven prices do not yet prevail. All three countries have to some extent unbundled their power sector, creating several functional units within the parent holding company, which are ring fenced with varying degrees of financial and managerial independence. The hope was that improved accountability of smaller business units and transparent cost-reflective pricing would cause the business units to gradually move to profitability. While the power sectors in all three study countries still show a high degree of government ownership or operational involvement, the functional unbundling of the power sector into government-held companies has been envisioned as a prelude to a form of privatization. As noted in Chapter 2, Georgia has already sold some of power units to private companies.

There are two key differences, however, between government ownership or involvement in the power sector in the OECD and in developing markets, such as the three cases here. First, in the OECD, government involvement is clearly defined and circumscribed by the rule of law and regulation, regulatory structures are in place to assure equitable treatment of market players, and judicial recourse is available. Second, the domestic capital markets are sufficiently sophisticated to disclose, allocate, and reward risk efficiently regardless of who owns the assets. In each of the three countries studied here, arguably the government still needs to clarify and limit the extent of its interests and its role in company management, so that potential private partners need not fear loss of assets or changes in policy over time. Institutional capacities need to be strengthened through stronger mandate and greater resources for better actualization of goals, policies, and strategies.

As discussed in Chapter 1, while competition is seen as a driving force for greater efficiency, certain conditions must exist before competition is possible:

- players must be well-informed about prices and costs, so each has the choice of whether and how to participate in the market.

As yet none of the three study countries has a power sector that meets these criteria; the market size is small, qualified players are few, pricing is not fully market-driven or transparent, government-held companies do exercise market power, and market conditions are subject to political interference. Georgia has an operating wholesale market as well as a generation market, although neither is fully competitive. Viet Nam has the beginnings of a competitive generating market. They have functionally unbundled their vertically integrated power companies, and have created around each function a form of limited ring fencing that variously provides independent operations, financing, or management.

Moreover, although all three countries cite the commissioning of IPPs as a first step to competition, this has effectively not been the case. IPPs in all three countries have rarely introduced real competition because most sell power to the grid on the basis of individual contracts or power purchase agreements (PPAs), although competition is introduced at the procurement stage. The arrangements are closer to government procurement for power than to market competition and should be viewed primarily as an interim step toward diversification of the generating market. Such arrangements provide incentives for investors to supply power, but not to compete. The case study countries propose reviews of their IPP PPAs to make them more market-based, and perhaps introduce new procurement methods for new IPPs. One possible reform would be to use IPPs as merchant plants selling into a competitive power pool, which would in fact be a step toward real competition in generation. The experience with IPPs in the United States followed a somewhat similar learning curve. Initially, many IPPs were granted preferential takes and feed-in tariffs that assigned all risk to the purchasing utilities, arrangements that ultimately resulted in market and financial problems for the utilities. However, over time, most IPPs in the United States have evolved into free-standing merchant plants selling into competitive generation markets, a scheme far preferable for containing risk.
Private investment interest in transmission is complicated by the fact that transmission involves economies of scale and high fixed costs and is viewed as a natural physical monopoly. As such, the rates and operations for transmission will probably always be regulated, and the potential for profit is limited. Under traditional regulation of vertical monopolies, transmission was more or less just a way to reach customers, and not a business in itself, and tariffs were set on the basis of cost-plus pricing. But with unbundling, no good regulatory scheme has yet been devised to assure efficient performance and good investment decisions for stand-alone transmission. Owners and operators have insufficient certainty about demand on a daily basis and ability to plan system development. The limited potential for profit and the lack of planning capability thus deter private investment in transmission. Nonetheless, private parties will invest if they see profits can be made from more efficient system management and efficient pricing, and if they can expect to have freedom to make independent investment, management, and operating decisions. Georgia has successfully privatized its power distribution, in large part for such reasons.

6.3. Risk

Several general and specific risks can affect the outcome of investment in the power sector. These include changes in general economic conditions that affect electricity supply and demand, regulatory and political risks resulting from government interference, market risk relating to volume and price of sales, uncertainties about fuel price and availability, risks associated with lack of diversity in investment or technology and the size of the investment program, and financial risks due to choices of financial instruments.

In principle, the cost of each risk should be incorporated in the cost of the investment and reflected in the price of power. For this reason, a key element in all financing assessments is identifying each risk, its cost, and how to manage it. In negotiating contracts with private generators, governments need to be aware of all relevant risks and their costs, and must seek to assure their efficient allocation to the parties that can manage the risks best. Governments themselves should not accept the risk for elements not under their control, such as construction delays or cost overruns. Transparency in risk negotiations is imperative for efficient and equitable allocation of risk.

In OECD countries with long experience in private investment, risk is routinely priced and managed. Information about potential investments is available transparently and financial instruments are available to allocate and mitigate risks and their costs. Where there is no well-developed domestic capital market, players need to be more wary of risk allocation. Risks may easily and unfortunately be inefficiently assigned to the weaker negotiator or inexperienced party. The proper assignment of risk is particularly important because power market liberalization greatly changes investment incentives, shifting risk from consumers to decision makers and investors. Under monopoly utilities, the customer bore the cost of all risk. In a competitive market, risks are assigned or their assignment is negotiated. Inefficient or incomplete unbundling can result in risks being assigned to those without authority or power to manage them effectively, if at all.

Private investors that enjoy no market power may try to reduce risks by proposing lower cost, rapid-build technologies. This may lead to a preference for short-term, low-capital-cost projects that minimize many of the potential costs of financial and market risk. Projects with long lead times and high capital costs—even if they are more efficient in the longer term—may be rejected in favor of short-term stop-gap investments. This has been a particular problem in Sri Lanka, where a 25-year delay in the construction of a least-cost coal-fired power plant resulted in less efficient plants being built in the interim. As discussed in Chapter 3, pressure from aspiring IPPs and from donors caused the Ceylon Electricity Board (CEB) to procure 10 IPPs (all oil fired) and to build two oil-fired power plants of its own, to assure system supply. But the costs of generating power (both fuel and capacity costs) were driven up significantly above average system costs. This problem occurs in many sectors.
6. Conclusions and Lessons Learned—Power Sector Reforms, the Ways Forward

and it is not unusual for delays in starting planned multinational, as well as complex national projects, to result in the plans being superseded by ad hoc investments.

Capital markets provide for long-term investment needs, largely by supplying financial instruments that effectively assure investment liquidity, allowing the market to finance long-term projects through a series of short-term transactions, risk being bought and sold with each short-term transaction. Long-term bonds and equity shares, for example, are seldom held to the end of a project, but are bought and sold many times over in the interim. Risk management schemes used in the OECD and available to developing markets include public-private partnerships, or limited recourse project financing, where the investment project itself is the equity and any recourse for losses does not reach beyond the value of the project itself. The revenues of the project and not the assets of the sponsors or the utility are liable to service the debt. In countries without active domestic capital markets, investment assets are less liquid and investors may seek to minimize their risk by insisting that the government put up loan guarantees or that project sponsors contribute significant equity. The greater the perceived risk the more equity will be demanded.

6.4. Pricing

Transparent and efficient pricing is key to securing financing. Inefficient pricing was largely responsible for the economic collapse of the power systems in all three countries studied, as revenues did not cover costs. Negotiated and ad hoc pricing for power generation still prevails in all three countries, even in Georgia and Viet Nam, which are experimenting with competition at least for generation. As noted, a large part of generation in all three countries comes from IPPs with varying pricing arrangements and PPAs that are not market driven. In Viet Nam, for example, generation prices are the largest component of the retail tariff. At present, 90% of sales are covered by long-term financial PPA contracts, the prices of which have been negotiated between generators and the government. In Sri Lanka, the CEB has been forced to resort to a mix of short-term borrowing and simple nonpayment of fuel bills to finance needed generation and power purchases from IPPs. The situation has worsened with a severe drought requiring additional thermal generation and with no tariff adjustments.

Efficient pricing will signal whether supply is inadequate or in excess; whether demand is shifting in volume, by region, or by customer type; and whether new investment is needed. In some OECD countries, electricity prices in competitive power markets rose after power sector reforms began, sometimes in price spikes signaling short-term demand and capacity mismatches, and sometimes due to perverse regulatory incentives. In some of these cases, regulators allowed the market to respond freely with more power (short term) or more capacity (long term) or more efficient use of power. Each supplier and market player could make its own decisions about whether to invest, increase generation, or cut back on use in response to higher prices. In some cases, regulators capped the price increases, sometimes out of concern that a dominant player could be abusing market power. But such caps frustrate efficient decision making and the ability to find the most efficient balances between demand and supply. Such political intervention, motivated by a fear of market failure, can easily cause the feared market failure (International Energy Agency 2005). Price hikes due to temporary problems, such as drought, do not necessarily signal a need for investment so much as for system diversity or flexibility. Sri Lanka has used load shedding to deal with temporary capacity shortages resulting from project delays or below-average rainfall; introduction of IPPs has been a longer-term approach. How regulators respond to market pricing signals will significantly affect the successful outcome of the market response.

All three countries have taken steps to restructure their generating subsector, although market-driven prices do not yet prevail. In all three, reforms in IPP contracting procedures have been proposed or introduced. Some form of limited competition has been created in Georgia and Viet Nam, starting with a limited number of players, and with plans to
expand the program to all generators selling on a market basis into a competitive generating market. So far, their generation markets simply do not have enough players to create real price competition. All three countries have also taken steps in tariff reform. New tariffs have been promulgated and are at least nominally in effect. In Sri Lanka, some effort has been made to provide transparency in tariff setting: all input information, calculations, and calculated costs of supply used in initial tariff design have been published for public knowledge and debate, including the costs of each licensee and the pass-through costs of electricity supply. However, submissions have not been updated and revisions have not been made as scheduled or as required. In all three countries, the tariff-setting process lacks transparency, and tariff schemes retain some of the exemptions to standard and regulated pricing that reform sought to eliminate. Some pricing arrangements may in fact be quite efficient, but because they are not derived or applied transparently, they cannot serve as credible signals for buyers or sellers, or for investors considering the potential profitability of power sector financing. Transparency would reveal the need for specific pricing reforms and is essential to achieving efficient pricing and investment and full competition.

Although the power sectors in most OECD countries are competitive, they are not free of subsidies, most notably for renewable generation. Because the technologies for generation from renewable resources cannot be profitable at current market prices, they are subsidized as a matter of environmental policy at a high cost in virtually every OECD country. In Germany, for example, households on average pay a €6.23 cent per kilowatt-hour surcharge to fund renewables. In most OECD countries, renewable power is given preferential dispatch and is purchased from generators at costs above the system average. Similar provisions such as feed-in tariffs have been incorporated into the pricing schemes of all three study countries. These subsidies have severely distorted the market for power, and the European Union is now developing guidelines for market-based measures to replace the subsidies (Lewis and Chee 2014).

OECD countries also subsidize low-income consumers, usually through reduced rates (“lifeline tariffs”) for low consumption levels. The lifeline tariff approach is used in the three study countries. Other approaches might include income supplements, or providing free power up to some income or consumption level. Subsidies for low-income consumers are perhaps even more important in developing markets (such as Sri Lanka and Viet Nam) where poverty rates are high or rural access to grid electricity is costly to provide. Generally, the poorest groups tend to have to spend a higher proportion of their household income on electricity than do households with average incomes.

6.5. Regulation

Regulation can be distorted when the government owns and operates a substantial part of the power sector. Conflicts of interest often arise between government as regulator and as a regulated entity. Thus, the government needs to clearly define its interests and draw boundaries between its different roles. To facilitate investment, the roles of government and the regulatory regime need to be set out clearly during the reform process, as it
6. Conclusions and Lessons Learned—Power Sector Reforms, the Ways Forward

6.6. Security of Supply, and System Planning and Reliability

Power supply that largely depends on a single technology or imported source of fuel is vulnerable to supply interruptions or price volatility. Georgia, for example, is largely dependent on hydropower, supplemented by gas-fired thermal power, fueled by gas imports. Given the counter-cyclical nature of hydro generation, with supply peaking in summer when demand is low and dropping in winter when demand is high, Georgia will need thermal power and hence gas imports until the composition of generating capacity changes dramatically. In fact, Georgia’s vulnerability to imports of power and gas will likely grow if the government proceeds with its plan to have 100% hydro power.

Both Sri Lanka and Viet Nam also depend significantly on hydropower. Sri Lanka’s vulnerability is dependence on imported oil for thermal generation, again with vulnerabilities to international supply and price volatility. Sri Lanka has drawn up ambitious plans to increase the use of large-scale renewable energy sources such as biomass, wind energy, and photovoltaic systems for more localized use. But so far, such investments have not been successful.

High dependence on a single fuel for power generation is not unusual in OECD countries—for example, coal and gas in the United States, gas in the United Kingdom, nuclear power in Belgium and France, and hydropower in Austria. But to a large extent the dependencies can be mitigated by power exchanges through integrated grids, or by changing suppliers. Options are more limited in the three case study countries.

Historically, system planning for expansion and for assuring security, reliability, and adequacy of power supply fell to the integrated utility company. With unbundling and institutional restructuring, clear responsibility for system planning and development has been lost. In some cases, as in the United States, the government may put out an energy plan, but it is important for investors to know the regulatory environment they will be operating under before they invest. But while freedom from arbitrary political interference is clearly important, completely isolating the regulation of electricity services from larger social and economic considerations is neither possible nor desirable, as governments are responsible for reconciling industry and consumer interests. The crucial point is that any governmental influence in regulation should reflect national, not special, interests and should be free from abuse of political power or corruption.

As restructuring begins to unbundle and divest the power sector of public ownership, continued application and enforcement of consistent, neutral, and efficient regulation in a transparent manner will be absolutely necessary. Without this, no market entrant can be confident about operating conditions or revenue potential. Nonetheless, even with the best of intentions and plans, regulation can have unintended consequences. A major case in point is the collapse of the California power market when retail prices were capped but fuel and generation prices were unregulated. Utilities could no longer afford to supply power and regulatory changes were required urgently. Regulators must be prepared to detect such mistakes and flexible enough to amend the regulations accordingly. One way in which many OECD countries foster competitive neutrality is to make general competition law applicable to the power sector. This in principle should facilitate new market entry, protect captive customers, and control the reaggregation of market power after unbundling (a major issue in Georgia, as highlighted in Chapter 2). Georgia has a general law on competition, but it is not applied to the power sector.

The regulatory system promulgated for power sector reforms in all three countries is impressive in principle but is not fully implemented. All three countries acknowledge this problem, and have targeted changes for the next round of reform measures. Georgia has gone furthest, having recently signed the EU–Georgia Association Agreement, which provides in part for the eventual harmonizing of Georgia’s power sector with regulatory and institutional arrangements of the European Union.
is not binding on investors or on the power sector. Binding, systemwide planning is seldom possible in competitive markets. Both Sri Lanka and Viet Nam have system expansion plans that could reduce some of their system vulnerabilities, but the plans are not being implemented. Georgia has yet to promulgate a new long-term energy plan, but efforts to produce one are now under way. The government’s stated policy of having 100% hydro generation would compound the present import and technology vulnerabilities and the full implications of this policy need to be considered. As already noted, Sri Lanka’s frustrated attempts to realize a least-cost system expansion resulted in ad hoc high-cost plants being built that were not elements of the long-term plan.

While investment planning deals with long-term supply security, some short-term supply security and reliability considerations are related to unbundling and to power sector reform. In terms of transmission and distribution, all three countries have made great strides with improving their grids’ operation and management. Significant lessons were learned in Georgia from the takeover of Telasi by AES; from the management by OECD firms of its transmission and wholesale markets; and from the installation of state-of-the-art grid management technology, financed by foreign investment. System losses in all three countries and on transmission and distribution systems have dropped dramatically since reform started, reflecting in large part significant investments in the sector. Viet Nam, for example, maintains the “n-1 standard” on its grid.40

In the medium term, more efficient transmission means running closer to security limits for longer periods. This has led to security concerns in the OECD as margins have tightened, leaving less spare capacity in case of congestion. Power companies in the OECD have tended to address this problem by integrating and merging power systems across regions and between countries. Better transmission can ease generating requirements by connecting distant generators to load centers. These larger interconnected areas have greater flexibility of supply but also more potential vulnerability. Local problems can immediately be transmitted across large integrated systems. Such cascading power failures have occurred in the OECD—for example, in Canada, Denmark, Italy, Sweden, Switzerland, and the United States. However, for the time being, tight margins do not appear to be a problem in the three case study countries.

In the generating sector, medium-term inefficiencies have occurred as reserve margin requirements have changed. Given better transmission flexibility, most reserve margin requirements in OECD countries have been reduced. At the same time, many OECD countries require a growing share of the generating market to be covered by renewable power, which is available intermittently. Power companies have been required to maintain reserves of readily available fossil fuel power plants as back up to assure a continuing reliable power supply despite a high degree of intermittent generation. Lessons to be learned from these OECD experiences include the need for:

• better information, monitoring, and control technologies for grid management;
• agreements among transmission system managers that better clarify individual and shared responsibilities;
• better alignment of accountabilities with responsibilities and authority; and
• better and less distortive incentives for renewable power, transparency, and enforcement of agreed principles and activities.

Increasing the portion of power generated from renewable sources will also help the three countries achieve supply security in the long-run.

### 6.7. In the Long Run

Long-run plans for further power sector reform in Georgia and Viet Nam include developing a competitive electricity market at the level of generation, and wholesale and retail sales. Sri Lanka does not have such ambitious plans. Creating full

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40 A power system can be described as being “n-1 secure” when it is capable of maintaining normal operations (i.e., reliably delivering electricity of a given frequency and voltage subject to technical limits) in the event of a single credible contingency event, such as the loss of a transmission line, generator, or transformer (International Energy Agency and OECD 2005).
competition will require much more aggressive reforms than have currently been realized in either Georgia or Viet Nam. In both cases, legislative and executive measures designed to create competition have been amended, and in some aspects these changes have altered the original tenor of the authorizations; some reform measures have been weakened or their implementation delayed. The governments retain strong ownership and management interest in the power sector, making genuinely independent regulation difficult and complicating decision making in system management. Viet Nam has not been able to create a truly independent and competitive generating sector. Georgia has introduced generation and wholesale competition, but vertical reintegration and negotiated PPAs militate against full competition at least in the short-run.

Moving the reform agenda forward requires implementing the principles and procedures enacted in law (as in Georgia and Sri Lanka) or set out in a road map (as in Viet Nam). Next steps proposed for each country are as follows.

**Georgia**
- Remove transactions that are not based on promulgated tariffs and disclose costs behind all tariffs.
- Introduce regulatory provisions to encourage energy efficiency combined with effective metering and time-of-day pricing in consumer tariffs.
- Introduce feed-in tariffs for new power plants.
- Ensure transparent and independent regulation by confirming the regulator’s independence.
- Pursue the Georgian electricity market model adopted in December 2013 to create a market operator in 2015.
- Complete and implement the long-term expansion plan currently being prepared by the Georgian State Electrosystem and the Ministry of Energy.

**Sri Lanka**
- Implement fully the tariff methodology agreed by the Public Utilities Commission of Sri Lanka and the licensees.
- Fully separate the transmission and distribution licensees’ revenues from the Ceylon Electricity Board (CEB).
- Create a bulk supply transactions account to manage all income from distribution licensees and payments for generation and transmission, with reporting to the Public Utilities Commission of Sri Lanka.
- Establish a regulatory review of new generation projects and power purchase agreements, and the long-term generation expansion plan.
- Finalize and implement the current draft grid code to formalize technical regulation and establish national standards for the design and safety of the distribution system.
- Establish six independent companies from the CEB: the CEB Generation Licensee, CEB Transmission Licensee, and CEB distribution licensees 1 through 4.
- Move toward a competitive wholesale market by placing the retiring oil-fired independent power producers and CEB-owned power plants on this market.
- Allow merchant power plants and power wheeling to operate.

**Viet Nam**
- Combine transmission ownership, system operations, market operations, and the single-buyer functions into a single entity independent from the rest of the sector.
- Separate fully the day-to-day operations of generation companies from Viet Nam Electricity and allow them to pursue normal commercial objectives as independent companies.
- Put in place a regulatory framework for ring fencing, codes of conduct, and confidentiality requirements. Audit the compliance of generation companies with these arrangements.
In the longer run, as electricity markets and domestic capital markets develop in the three countries, governments, planners, system operators, and regulators must learn to trust these markets as the supplier and provider of adequate capacity, power supply, and services, with largely self-regulating response and control mechanisms, providing transparent information and sufficient financing. To this end, the OECD examples can provide both comfort for and guidance on the possibilities for investing in and developing reliable, financially viable, and economically efficient power sectors.
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Assessment of Power Sector Reforms in Asia: Experience of Georgia, Sri Lanka, and Viet Nam

Synthesis Report

This report examines three economies in different parts of Asia—Georgia, Sri Lanka, and Viet Nam—that introduced power sector reforms in recent years to create a commercially viable and efficient power sector. Each took a different route in moving away from a monopoly state-owned utility toward the common goal of a competitive, market-based, and better-regulated power sector. This report documents the broad spectrum of their power sector reform efforts, experiences, and relative successes as well as shortfalls, then uses international standard indicators to assess their economic, social, and environmental outcomes. Other economies should be able to draw valuable lessons and insights from this report for their own power-sector planning and policy and strategy formulation.

About the Asian Development Bank

ADB’s vision is an Asia and Pacific region free of poverty. Its mission is to help its developing member countries reduce poverty and improve the quality of life of their people. Despite the region’s many successes, it remains home to the majority of the world’s poor. ADB is committed to reducing poverty through inclusive economic growth, environmentally sustainable growth, and regional integration.

Based in Manila, ADB is owned by 67 members, including 48 from the region. Its main instruments for helping its developing member countries are policy dialogue, loans, equity investments, guarantees, grants, and technical assistance.