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Impacts of Electricity Market Reforms on the Choice of Nuclear and Other Generation Technologies

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IMPACTS OF ELECTRICITY MARKET REFORMS ON THE CHOICE OF NUCLEAR AND OTHER GENERATION TECHNOLOGIES

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FOREWORD

Electricity industries around the world have faced radical reform for the last 20 years, with mixed outcomes across countries. In general, there has been a significant disparity between the initial expectations of the reform and its actual outcomes. The technological landscape — expressed in terms of fuel mix, capacity and generation shares — looks considerably different from what was expected.

Against this backdrop, the IAEA implemented a multicountry study in 2010–2014 to develop insights into the following questions: What has been the influence of reform and non-reform factors in shaping the technological landscape in various countries? More specifically, what are the prospects for nuclear power under alternative market reform schemes?

This publication summarizes the insights drawn from detailed studies undertaken by researchers in participating IAEA Member States. A consultative process among participants was facilitated by the Secretariat by organizing two technical meetings in Vienna and via electronic communication.

We acknowledge the contribution of D. Sharma, Director of the Centre for Energy Policy and Director of the Energy Planning and Policy Program at the Faculty of Engineering and Information Technology, University of Technology, Sydney, for compiling and updating this publication. The IAEA officers responsible for the project and this publication were F.L. Toth and N. Barkatullah of the Division of Planning, Information and Knowledge Management.

EDITORIAL NOTE

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SUMMARY

This report analyses the impacts of electricity market reforms and non-reform factors on the selection of electricity generation technologies, including nuclear power, by investors. Reform related factors include restructuring, privatization, regulation and the introduction of market mechanisms in electricity generation and trading. Non-reform factors refer to other attributes that have important influence on shaping investors' choice of generation technologies. These factors include, for example, international fuel prices, concerns about climate change and energy security, and anti-nuclear sentiments.

A country case study approach has been adopted in developing the material presented in this report. The Member States involved in this study are classified into three categories: mature, transition and potential markets. Mature markets are those where electricity reforms have already resulted in the establishment of competitive generation and retail segments supported by wholesale, spot, pool or power exchange mechanisms, and regulated monopoly networks operating in open access regimes. Transition markets include countries where electricity reform has progressed significantly but has not yet attained the level of market development characterizing countries with mature markets. Potential markets include countries where there has been a considerable debate about establishing electricity markets but the degree of implementation is insignificant.

Each country case study is organized around the following themes: rationale for reform; nature of the electricity market reform; how has the reform shaped the allocation of investment risk in electricity markets and how has this risk allocation influenced investor choice of generation technologies; and finally, how have non-reform related factors influenced investors' choice. The main points relating to each of these themes are presented below.

Rationale for reform

In *mature markets*, the reform of the electricity industry was undertaken as part of wider economic reform programmes driven by a range of factors including the globalization of the world economy and pressures to improve domestic and international competitiveness of the national economies, trends towards smaller government and emerging beliefs in free market principles. These reform programmes were given further credence and immediacy by the economic crises of the 1980s (for example, the debt crisis in Chile and the stagflation in the United States of America (USA)).

More recently, the need to address climate change and energy security challenges was added to the list of rationale for reform in these countries. This has resulted in the incorporation of special incentives in some markets (most notably in Germany and the United Kingdom (UK)) to support the uptake of renewable technologies as a way of reducing greenhouse gas (GHG) emissions and diversifying sources of power generation. In other countries (e.g. Chile), long term contract auctions have been introduced in response to the power shortages of the early 2000s. These auctions are expected to provide investors with revenue stability needed for financing power projects, especially large scale and capital intensive developments.

In *transition and potential markets*, where the electricity industries were typified by electricity supply trailing electricity demand, rapidly rising demand, weakly connected systems and financially constrained exchequers, the main rationale for electricity reform was to attract much needed private investments (especially, foreign) to develop the power systems, alleviate electricity shortages and thereby, it was argued, vivify the countries' economies.

Electricity industry reforms in transition and potential markets were also advocated by multilateral financial organizations (such as the World Bank). These organizations — driven by their resurging faith in neo-liberalism — have actively engaged in promoting and implementing electricity reforms in several countries.

Planners and policy makers have aimed to achieve a rather diverse and sweeping range of objectives: reforming their electricity industries, encouraging private investments, improving the efficiency of power supply, lowering electricity prices, providing improved services and ensuring economic prosperity. The logic behind various objectives is not always clear. For example, how does one restructure the existing below marginal cost tariffs prevalent in most transition and potential markets and provide lower tariffs? How does one promote sustainability when the pool mechanisms generally favour generation from low cost, but highly polluting fuels — as is the case in several mature markets (e.g. Australia) that rely primarily on coal for electricity generation?

In summary, electricity reforms have been strongly motivated by ideological considerations, promoted almost as an article of faith. This observation is substantiated by the facts that much of the reform edifice has been built on shaky foundations, no comprehensive ex-ante analysis was made of the why and how and about the possible consequences of the reform, inherent contradictions are ample (see above), the populist language used to endear the programme to the wider populace and the rather prejudiced ex-post analyses. This becomes somewhat understandable if one considers the fact that much of the philosophical imprimatur for these reforms was provided by the neo-liberal polity ascendant in the 1980s and 1990s, accompanied by the significant geostrategic shifts in the global military and economic balance in the 1980s. The argument here is not whether reforms were or are warranted or not. Rather, the argument is about the clarity of focus on the real objectives of the reforms.

Nature of electricity market reforms

While the depth and pace of reforms have differed across countries, the nature of the reforms implemented by various countries was essentially the same. These programmes were largely based on the neo-liberal free market ideology. Accordingly, the main elements of these programmes included a structural unbundling of competitive (e.g. generation and retail) and monopoly (e.g. transmission and distribution) segments of the industry; introduction of competition in generation and retail; development of non-discriminatory access arrangements for transmission and distribution; replacement of centralized state directed regulatory arrangements with market-based arrangements; and privatization. These elements are analysed in this report in terms of the following themes: industry structure and ownership arrangements; regulatory arrangements (including network regulation, end user prices and special incentives); and market mechanisms for electricity trading.

Industry structure

In *mature markets,* the electricity industry has been restructured to facilitate the functioning of market mechanisms. Vertically integrated power companies have been unbundled into generation, transmission, distribution and retail. But a growing tendency for vertical reintegration between generators and retailers has been witnessed in recent years in many countries, e.g. Australia, New Zealand, the UK and Germany. Large generators have tendered to acquire retail businesses, typically during the privatization process.

Notwithstanding nearly two decades of efforts to introduce competition in the generation and retail segments, the degree of competition in generation remains on average ‘medium’ in most *mature markets*. This suggests that the 'natural' structure of the generation market is oligopolistic. This is understandable if one considers the magnitude and lumpiness of investments required to establish electricity generation capacities and the priority of governments to protect residential consumers from exposure to high electricity prices.

In *transition and potential markets*, the generation segment has been separated from the conventional vertically integrated companies. Private investors as independent power producers (IPPs) have also been encouraged to participate in the generation business. The remaining functions of the power sector (transmission, distribution and retail) are still largely undertaken by vertically integrated entities which normally act as the 'single buyer' of electricity and supply electricity to the consumers.

Ownership

In *mature markets,* the privatization of the electricity industries has been undertaken primarily by two means: selling existing publicly owned electricity assets and inviting private investors to engage in new power projects. The privatization process has resulted in an overwhelmingly mixed public–private ownership of the electricity industries except in some countries (such as Chile, UK and USA) and some states of Australia where private ownership dominates.

In *transition and potential markets,* private involvement in the power sector has been increasing since the initiation of the reforms, mainly through their ownership of independent power generators. However, private participation in the sector is still limited and the sector is dominated by public ownership.

Regulatory arrangements

Mature markets are generally characterized by a high degree of regulatory independence. The responsibility of the regulator is largely confined to monitoring and compliance, licensing and regulation of the general market (i.e. to prevent the abuse of market power) and networks (i.e. to ensure non-discriminatory access to monopoly networks), and network access pricing. Besides, in many countries with *mature markets,* electricity prices for small consumers are still subject to some form of regulation (i.e. price caps).

In *transition and potential markets,* the governments continue to have a significant role in the regulation of the industry, including licensing and the setting of electricity tariffs for generation, line businesses and end users. The electricity tariffs in most countries are determined by the 'cost of service' principle.

In *mature* as well as in *transition and potential markets*, special regulatory incentives are provided to support the uptake of electricity generated by renewable sources. In some countries (e.g. UK, USA and China), nuclear energy also receives some form of regulatory support.

Market mechanisms

Formal competitive markets have been established in most countries with *mature markets*. They are generally organized in the form of a pool market or a power exchange. In a pool market, generators are typically dispatched centrally by the system operator to meet demand. In a power exchange, generators are self-dispatched and the system operator is only responsible for balancing the market in real time. This obviously has implications for technology choices in electricity generation.

Countries with *transition and potential markets* have not yet established formal market mechanisms and power continues to be sold through some variation of the single buyer model with a few exceptions such as India and the Philippines where wholesale competitive markets have been established but still have not reached the level of development as prevalent in mature markets.

Reforms, risk allocation and their impacts on the generation technology mix

Prior to the reforms, there was a general tendency for investors in all countries included in this report to choose large scale, capital intensive technologies (including hydropower, nuclear and coal) for capacity additions. Between 1980 and 1990, generation capacity in countries included in this report increased by 336 GW. More than half of this increase came from thermal capacities, especially coal, 18% from hydro and 19% from nuclear.

This tendency to build large scale power projects is understandable if one considers that prior to the reform investment risks were largely allocated to the consumers through the public ownership of the industries and regulated electricity tariffs based on 'rate of return' principles. Such risk allocation tended to encourage investments in large scale power projects because public investors would not be punished by uneconomic investment decisions.

In *mature markets*, electricity market reforms (restructuring, privatization and reregulation), have gradually shifted the investment risks from the consumers to the investors. Investors now need to consider financial risks associated with alternative generating technologies when making technology choices. A range of measures has been developed for investors to manage these risks, including the establishment of formal financial markets, provision of bilateral contracts through over the counter (OTC) markets, long term contract auctions and reintegration between generators and retailers.

These changes have contributed to a gradual shift in the technology mix of existing capacities but particularly of new capacities. In the reformed industry, investors are motivated to select generation technologies with lower investment risks and shorter construction times, especially natural gas. For example, a noticeable increase in the role of natural gas in generation capacity has been observed in the UK from 6% in 1980 to 42% in 2012.

In *transition and potential markets*, limited progress has been made in reforming the electricity industries. In these markets, restructuring and privatization are limited and mainly confined to the generation segment of the industry. Regulators have been established with limited autonomy. Some important regulatory functions, especially licensing and tariff setting, still remain with the government. Formal market mechanisms have not yet been established and power continues to be sold in these markets through some variation of the single buyer model.

In the single buyer model, investment risks are largely allocated to the consumers. The IPPs supply electricity under power purchase agreements (PPAs) which usually allow them to pass through their risks to the single buyer. The single buyer delivers electricity to end users under regulated prices that are largely determined according to 'cost of service' principles. Reforms in these electricity markets have only broadened the financial bases for new generation capacity and have had little impact on the investors' choice of generation technologies. In these markets, all types of generation technologies have enjoyed considerable development, especially after the reforms. Total capacity in transition and potential markets increased from 138 GW in 1980 to 292 GW in 1990 — a nearly twofold increase. In the following years to 2011, capacities in these markets increased more than fivefold to 1570 GW.

Impacts of non-reform factors on the generation technology mix

In *mature markets*, the tendency to build small scale, less capital intensive generation capacities was assisted by several non-reform factors, particularly modest demand growth, climate change, energy security and anti-nuclear attitudes. In most countries with mature markets, electricity demand grew at relatively modest rates, due to the general shift away from more energy intensive to less energy intensive industries and energy efficiency improvements. This has reduced the scope for investors to build large baseload plants (e.g. coal).

The growing concern about climate change, especially in the 2000s, has resulted in the implementation of several measures to support the uptake of low carbon technologies (e.g. gas and wind). As a result, gas fired and renewable (especially wind) technologies have attracted the bulk of new investments while relatively less interest has been witnessed in coal-based technologies.

Increasing reliance on natural gas for electricity generation (especially in Europe), combined with soaring gas prices in the 2000s, has given rise to concerns about energy security. These concerns have contributed to introducing policies aimed at diversifying energy sources for electricity generation. Renewable technologies have been obvious beneficiaries of these policies.

Nuclear power is a highly contentious issue in mature markets. There are sharply contrasting opinions amongst the political parties and the populace at large. Overall, the public sentiment in many countries in this group is anti-nuclear. The accident at the Fukushima Daiichi nuclear power plant (NPP) in March 2011 has further deepened this sentiment in some countries. Due to the political sensitivity of nuclear power, many countries do not consider it as a near term option in their future generation technology mix.

In *transition and potential markets*, technology choices have been predominantly influenced by non-reform factors such as fast demand growth, climate change, energy security and public opposition to nuclear power. Demand for electricity has been growing significantly to support economic growth. This has encouraged the deployment of all types of generation technologies. Concerns about climate change and the security of electricity supply have also encouraged the diversification of generation technologies. For example, the Chinese government has actively promoted the strategy of optimizing thermal power, orderly developing hydropower, accelerating nuclear power and promoting renewable energies in order to meet the country's rising demand for electricity and to mitigate the increase of GHG emissions, especially from the use of coal for electricity generation.

The deployment of nuclear energy has been slow in some of the *transition and potential markets* due to public opposition. However, some countries (e.g. China, India, Indonesia, South Africa and Thailand) have ambitious plans to develop nuclear power. The accident at the Fukushima Daiichi NPP has polarized the public opinion on nuclear power in these countries and may delay the introduction or expansion of nuclear energy, but its attractiveness is likely to increase in the years to come.

1. INTRODUCTION

1.1. BACKGROUND

Electricity market reforms have been underway worldwide for nearly three decades. The majority of developed countries and more than 70 developing countries have undertaken steps to reform their electricity industries [1]. Proponents of the reform argue that it has important implications for the generation technology mix in the electricity industry. Competition is expected to emerge as a result of privatization, restructuring and reregulation that would motivate investors to search for the cheapest generation technology mix [2]. In addition, competition combined with privatization would result in a gradual internalization of investment risks in power generation. Investors would have to factor in financial risks posed by alternative technologies when making their technology choices [3].

The literature shows a growing interest in the actual experience of electricity market reforms and their impacts on the generation technology mix (see Refs. [2], [3], [4], [5], [6], [7], [8]). So far these studies have exclusively focused on impacts of reform related factors on the technology mix. There is a lack of in-depth discussion about the impacts of non-reform factors (such as climate change and energy security) on the technology mix. It is widely acknowledged that these non-reform factors have an important influence on the investors' choice of generation technologies.

1.2. OBJECTIVES

The main objective of this report is to provide a better understanding of the impacts of electricity market reforms and non-reform factors on the generation technology mix, including nuclear power. How have the reform and non-reform factors influenced investors' decisions? A country case study approach was adopted to analyse this question. Participating countries are divided into mature, transition and potential markets.

Mature markets are those where electricity reform has already resulted in the establishment of competitive generation and retail segments, supported by a wholesale, spot, pool or power exchange mechanism, and regulated monopoly networks operating in open access regimes.

Transition markets include countries where electricity reform has progressed significantly but has not yet attained the level of full market maturity evident in countries with mature markets. Countries in this category include China, India, Pakistan, South Africa, Turkey and some members of the Association of Southeast Asian Nations (ASEAN) (especially Indonesia, Malaysia, Philippines and Thailand).

Potential markets include countries where there has been a considerable debate on establishing electricity markets but actual progress is insignificant (e.g. Kenya).

This market (country) grouping provides an adequate coverage — in terms of geographical spread, socioeconomic settings, drivers of electricity reform, models of reform and experience with reform — for developing a panoramic perspective on the broader dimensions of electricity reforms, including their impacts on the uptake of generating technologies (including nuclear power). With a view to the similarities of pertinent characteristics of transition and potential markets, they are discussed together in some sections of this report.

1.3. USERS

This report is intended for a variety of stakeholders involved in strategic planning of the electricity sector, including policy makers, policy analysts, policy advisors, power sector regulators and utility operators in Members States of the International Atomic Energy Agency. Those interested in the impacts of various degrees and types of power sector reforms on the prospects for different generation technologies, especially nuclear power, may find the report particularly interesting.

1.4. SCOPE AND STRUCTURE

The report is based on the analysis of key topics that were assigned to national experts who prepared country case studies. The topics include: rationale for reform; nature of electricity market reform; how the reform has influenced investors' decisions regarding technologies; and how have non-reform related factors influenced those decisions.

The remainder of the report is organized as follows. Section 2 provides an overview of the key threads of arguments that constitute the purported rationale for electricity market reform. An overview of the salient features of the reforms is provided in Section 3. Section 4 analyses the implications of electricity market reforms and non-reform related factors on the investors' choice of generation technologies. In Section 5, the wider implications of electricity reforms in various countries are discussed. Section 6 summarizes the main conclusions.

2. RATIONALE FOR ELECTRICITY MARKET REFORMS

2.1. INTRODUCTION

This section provides an overview of the key threads of the arguments that constitute the purported rationale for electricity reform for various countries in mature, transition and potential markets.

2.2. MATURE MARKETS

In **Australia**, the reform of the electricity industry was undertaken as part of the economy-wide reform, called the 'microeconomic reform' programme. The main driving forces for this reform included the globalization of the world economy and pressures to improve domestic and international competitiveness of the Australian economy, trends towards smaller governments, emerging belief in free market principles and perceptions about the inherent inefficiencies in the Australian electricity industry. The proponents argued that the reform — through competitive market pressures — will result in cost reductions and hence lower electricity prices for the end users. These, in turn, will provide significant economy-wide benefits that will enhance the domestic and international competitiveness of the Australian economy. Public approval for the electricity reform was sought through a mix of simplified arguments: lower electricity bills and significant savings for consumers, empowering people, improved profitability for businesses and hence more jobs, and the private ownership of the industry freeing up government resources for spending on schools, hospitals and roads [9], [10].

The reform of the electricity sector in **New Zealand** was undertaken in the mid-1980s as an integral aspect of the economy-wide, free market reforms. The proponents argued that the reform would improve the efficiency and effectiveness of the public sector and reduce electricity prices [11]. In the years 1995–1997, sustainable development was added to the list of motives for the reform. In the early 2000s, the electricity reform was promoted on the grounds that it will result in delivering electricity to all classes of consumers in an efficient, fair, reliable and environmentally sustainable manner.

In the **UK**, the electricity market reform was implemented in two phases. In the first phase (1990–2005), reforms were focused on strengthening the role of competition in wholesale and retail electricity markets, with the aim of reducing electricity prices by encouraging more efficient investment and management in the generator sector. Competitive entry into the generation market and privatization of the existing generator companies also opened the way for private capital to enter the sector, thereby relieving the strain on public finances. This phase of the reform culminated in April 2005 in the incorporation of the Scottish electricity sector within the market arrangements then applying to England and Wales.

In the second phase (2005–2010), the reform has taken a different direction with a continuously increasing emphasis on investments in renewable generation and a growing interest in new nuclear plants as a way to meet European Union (EU) and UK government targets for reducing carbon dioxide (CO_2) emissions and for increasing output from renewable energy sources. The start of the second phase can be identified with the passage of the Energy Act 2004 (that obliged the energy regulator to take account of ministerial guidances on the government's environmental and social policies) and the introduction of the EU Emissions Trading Scheme (ETS) in 2005. The emphasis on environmental policy aspects keeps increasing ever since. The Energy Act 2010 prescribes that the energy regulator must also consider CO_2 emissions reductions and energy supply security in its assessment of consumers' interests (its principle duty). In March 2010, the UK government issued an energy market assessment, formally announcing a new programme of review and reform intended to ensure that electricity markets support government policies on low carbon (i.e. renewable and nuclear) generation. In December 2010, the government issued a formal consultation document on the electricity market reform that proposes to offer developers of low carbon and flexible (i.e. load following) generation a stable feed-in tariff (FIT) for some years. The precise form of the FIT and the arrangements for allocating it were not specified in detail.

In the **USA**, the electricity sector reform, dating back to the late 1970s and 1980s, resulted from the culmination of several factors: consumer dissatisfaction with rapidly rising costs of electricity; conviction that electricity was not being supplied efficiently, early indications of underinvestment in new facilities, technological innovation (especially in small gas turbines) and the emergence of market economy philosophies [12].

In **Germany**, the electricity industry was reformed to implement the EU Directive motivated by the European Commission's conviction that liberalization, price deregulation and privatization would directly lead to competition in power generation and supply that would then result in lower prices for the whole of Europe. In addition, it also aimed to reduce the dependence on energy imports and to reduce GHG emissions [13]. In the energy concepts of 2010 and 2011, the objectives focus strongly on climate protection and environmental sustainability, especially on climate change mitigation by reducing GHG emissions by 21% relative to the 1990 level by 2012 in the context of the Kyoto Protocol, a reduction of 40% by 2020 (relative to 1990) as a national commitment, and a long term goal of 80–95% reduction of CO_2 emissions. Other aspects, especially security of supply, were treated as secondary topics.

Reforms were introduced in the **Lithuanian** electricity sector in 1997. These reforms aimed at transforming the industry from the regulated to a market-based arrangement, and moving away from governmental control towards commercialization, corporatization and privatization. The main objectives of the electricity sector reform (especially since 2010) have been to create a competitive electricity market and to ensure fair competition; to promote effective electricity generation; to ensure the reliability of electricity generation, transmission and distribution; to promote the development of the internal electricity market and electricity export; to modernize infrastructure; to promote transparency in energy pricing; to impose public service obligations related to the security of society; to protect the environment; to encourage electricity installations using local, renewable and secondary energy; to create favourable conditions for investments in the electricity sector; and to promote environmentally friendly technologies [14].

The reform in the **Polish** energy sector was part of the overall market oriented economic transformation. The main goal was to adjust electricity prices to the costs of service by introducing regulation by an independent regulatory body and by competition wherever possible, as well as by commercializing and privatizing state-owned enterprises. Under the centrally planned economy, electricity prices were set politically by the government at uniform levels throughout the country. Electricity prices for households were subsidized by industrial customers. The price of coal and lignite — accounting for over 90% of the fuel for electricity generation — were also set politically by the government.

In **Chile**, the reform of the electricity industry was undertaken as part of a larger agenda on economic and political reform in order to attract investments in the industry. This larger agenda was commensurate with the emerging beliefs in Chile about the need to enhance the role of the private sector and the markets, reduce state participation and liberalize prices.

These beliefs and the reform of the electricity industry were given further credence and immediacy by the economic crisis of 1982–1983. It was argued that the state's commitment towards its electricity industry was burdensome; the national electricity company (Empresa Nacional de Electricidad S.A. – National Electricity Enterprise (Endesa)) was exploiting its monopoly situation; confusion over the normative and entrepreneurial roles of the state that hindered the entry of other actors; the lack of transparency and economically efficient practices; and the lack of uniformity in price setting. It was further argued that these problems cannot be addressed within the energy sector and an economy-wide approach must be adopted, with the state playing a subsidiary role [12].

The **Colombian** electricity sector has undergone a profound restructuring process over the last two decades. The main drivers of the reform were: the intention to strengthen competition mainly in the wholesale market and secondarily in the retail market; the major blackouts of 1983 and 1992–93; the need to attract external funds to invest in power generation; and the belief that deregulation will improve productivity in the industry.

2.3. TRANSITION AND POTENTIAL MARKETS

The early stimulus for reform of the **Chinese** electricity industry came from the need to attract funds to overcome the crippling energy shortages of the mid-1980s. To keep up with the rapid pace of economic growth, the government took measures to achieve energy security. The case for the reform was given additional support in the mid-1990s by the argument that a market oriented reform could significantly improve the productivity and efficiency of the electricity industry and lead to lower electricity prices; promote competition; improve the power tariff mechanism; optimize the resource structure; promote the development of the electricity sector; improve electricity transmission and distribution across the country; and establish an independent open market structure that separates the functions of government and the enterprises. The narrative on the need for further reform shifted in the early- to mid-2000s. In 2005, the National Development and Reform Commission (NDRC), the State Electricity Regulatory Commission (SERC), the Ministry of Finance and other agencies worked towards the establishment of a regional electricity market accompanied by electricity tariff reform and market competition to encourage large users to purchase electricity directly from power generation enterprises. It was argued that reforms were needed to improve the international competitiveness of the Chinese economy [15].

In **India,** the drivers for electricity reform include a combination of internal and external factors such as the worsening financial situation of the State Electricity Boards (SEBs); endemic electricity shortages; increasing inefficiencies; poor quality of electricity supply; balance of payments crisis; capital shortage for investments in electricity infrastructure critical for supporting economic growth; and the pressures by international donor agencies [16].

The **Indonesian** government believed that the electricity reform will restore the financial viability of the industry, promote competition, introduce transparency and encourage more efficient participation by the private sector. According to the World Energy Council, the electricity industry reform aimed to encourage private investments to finance generation and adequate transmission infrastructure, increase the efficiency of production, reduce reliance on oil by developing domestic hydro and geothermal energy, diversify more into coal and gas, improve customer service by decentralization on a regional basis and corporatization of generation, transmission and distribution in Java-Bali and as integrated activities elsewhere, and conserve and use energy more efficiently.

In **Malaysia**, the main objective of the reform was to improve economic efficiency of the electricity supply industry and the economy as a whole. With a view to find new sources to finance the expansion of the energy sector, the government commissioned a number of studies to analyse the question of power sector privatization. The government enacted the Electricity Supply Act in 1990, thus started a chain of events towards privatizing the electricity supply industry in Peninsular Malaysia. The main objective of the privatization was to encourage private investments in the electricity industry in order to free up funds for other socioeconomic projects. Other objectives were to promote competition and subsequently improve efficiency and productivity in the electricity sector; to provide improved services at reasonable prices to consumers; and to stimulate private entrepreneurship and investments. The system was in accord with the National Development Policy that aimed at creating an efficient local commercial and industrial community.

In the **Philippines,** the government developed the Privatization and Restructuring Program for the Philippine Electricity Sector in 1993 as an attempt to remove structural flaws and to remedy the power crisis by attracting additional private sector participation in the electricity industry. However, it was not until June 2001 that the reform programme gathered momentum with the passage of the Republic Act 9136, also known as the Electric Power Industry Reform Act (EPIRA) of 2001. The reform was expected to accelerate electrification of the country; ensure the quality, reliability, security and affordability of electricity supply; ensure transparent and reasonable electricity prices in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippines products in the global market; enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors; release government resources that can be spent on education, health and agriculture; convert the power sector into an industry driven by competitive markets resulting in lower power rates; and foster economic growth in the country.

The initial impetus for the electricity sector reform in **Thailand** was given by the unprecedented growth in demand for electricity and the shortage of funds to expand generation capacities. The government initiated the reform process in 1992. The first step included the IPP and small power producer (SPP) programmes. Much of the focus of this reform was on facilitating private participation in electricity generation in order to alleviate immediate electricity shortages. The purported aim of this initiative was to help reduce the investment burden of the Electricity Generating Authority of Thailand (EGAT) by attracting private investments in electricity generation and to bring down the overall power generation costs to levels below the costs in the public sector. In the period 1998–2010, pressures to reform the industry further continued despite the alleviation of electricity shortages by the IPP and SPP programmes. The Asian financial crisis of 1997–1998 was the main catalyst for the introduction of additional market oriented reforms. The crisis caused a significant decline in electricity demand and hence created a condition of excess capacities. The drop in electricity demand combined with an appreciable depreciation of the Thai currency pushed the electric utilities into a precarious financial situation. This came in parallel with the loan conditions of the International Monetary Fund (IMF) that emphasized the privatization of the utilities. This gave a new impetus for reforms. In 1998, the government approved the Master Plan for the State Enterprise Sector Reform [17]. This market oriented reform, it was argued, would improve the efficiency of the electricity industry; lower electricity tariffs; improve the quality of service; draw private investments into the power generation sector; reduce the government's investment burden of financing expensive electricity infrastructure and hence enhance its capacity for investing in other priority programmes such as health, education and other social activities.

The government of **Pakistan** started to reform the power industry in 1985 to attract private capital as a means of dealing with widespread power shortages. In 2000, the country was stranded with excess capacity, principally costly IPP plants producing expensive electricity due to their reliance on imported fuel oil. This led to a revision of the government policy. The new policy included the introduction of a competitive bidding process for new generation and the promotion of indigenous resources, especially coal and hydropower. Besides, safeguarding the environment and keeping consumer prices within affordable limits also became central to the Policy for Power Generation Projects 2002 [18] and [19].

In **South Africa**, in the period leading to the democratic revolution in 1994, a debate revealed that apartheid policies had resulted in a highly fragmented local government system with poorly performing service delivery. There was a massive backlog in electricity connections to households in black neighbourhoods. There was also a perceived need for the consolidation of electricity distribution to improve the technical performance and financial viability of the industry so as to enable it to accelerate the electrification process. Another reform driver emerged in the mid-1990s in the context of the government's economic policy that sought to improve the efficiency of state-owned enterprises. Although Eskom was generally regarded as a better managed entity than other state-owned enterprises, it was also considered a candidate for further reform. Yet another reason for the electricity reform arose in the context of the energy policy debate in the mid- to late 1990s. There was a perceived need to avoid the mistakes of the past when Eskom heavily overinvested in capacity expansion. It was argued that there is a need to create an industry structure that allocates risk in a manner that encourages investment efficiency. The need for new generation capacity raised the question whether Eskom should build such capacity and what was the appropriate industry structure to encourage least cost investments [20]. The government's intention to reform the electricity market and have new generation capacity built by IPPs resulted in Eskom not initiating projects to build new power stations despite increasing demand for electricity and the impending supply gap. By 2005–2006, it became obvious that IPPs were not coming to the market (due to pricing, regulatory and environmental policy concerns) and South Africa urgently needed to build new power stations to meet growing electricity demand. Eskom then reinitiated its build programme. Due to time and capacity constraints, Eskom decided to return three of its mothballed coal plants to service (at significant cost and difficulty), to build two 1000 MW open cycle gas turbine power stations (to run on diesel) and to initiate programmes to build two 4800 MW coal power plants and one pumped storage hydropower plant (1333 MW). Despite the failed initial attempt at deregulation, the intention to involve the private sector in the electricity market prevailed. With reserve margins low and Eskom being limited in terms of the speed at which they could build new capacity, the private sector was re-engaged in 2008 to provide cogenerated power through the Pilot National Cogeneration Programme and the Medium Term Power Purchase Programme, and baseload power through the Multi Site Base Load Independent Power Producer programme in 2009. Finally, with the growing global drive towards CO_2 emissions reductions and clean energy, a policy was initiated to implement a renewable energy FIT scheme in 2009.

Since 2001, **Turkey** has been in the process of liberalizing its electricity market. The country has achieved significant progress in establishing competitive market structures in the energy sector by increasing the overall economic efficiency and encouraging new entry and investments. The Electricity Market Law came into force in March 2001 with the objectives of developing a transparent and competitive electricity market, achieving stability of supply, and ensuring high quality and inexpensive electricity. The ultimate purpose of this process was to create a fully liberalized system where the state acts only as a supervisory and regulatory authority instead of an investor and to create a competitive electricity market where private actors will make the investments. The most important aspect of the restructuring is the central role of competition in the market. The state started privatizing its generation and distribution facilities and also ensured that new investments are made by private investors to create and maintain a balance between demand and supply of electricity.

In **Kenya**, the internal pressures for reform can be grouped into three categories: technical, social and political. The technical pressures included high system losses, persistent power interruptions and electricity shortages. The social pressures comprised high electricity tariffs, alleged corrupt practices in the industry, rampant fraud and electricity theft, and low electrification levels, particularly in rural areas. The political pressures emanated from the demand by the populace for transparency, democracy and accountability. The external motivation for market reform arose from a variety of economic and political factors. The economic factors included the insistence of the World Bank to redesign electricity tariffs (equivalent to at least 75% of the long run marginal cost of electricity supply) with the objective of realizing at least 8% annual rate of return on assets. The influence of political factors on Kenya's electricity reform programme is evident from the preconditions imposed by the World Bank and the Industrial Development Association for providing funds for power sector development [21]. The Energy Act of 2006 created further provisions for private participation in the power sector. This was followed by structural reforms that led to the establishment of new institutions that were carved out of existing ones with the mandate to focus on roles that were identified as necessary to revamp the sector, build infrastructure and explore national energy resources.

2.4. SUMMARY

The salient features of the rationale for the electricity market reforms are summarized in Tables 1 and 2. The foregoing discussion and information in the tables lead to the following conclusions:

At the broadest level, based on the national case studies included in this report, the main drivers and objectives for electricity supply industry reforms in all types of markets have been to improve the economic efficiency and productivity of the electricity industry, to reduce the cost of producing electricity and to provide better services to the customers.

In *mature markets*, in addition to the above objectives, sustainability and reliability considerations have been priority objectives for the reforms. These considerations include promoting demand side management, reducing environment impacts, improving electricity supply reliability and removing pricing anomalies.

In *transition and potential markets*, the main objectives of the reforms have been to reduce electricity shortages, meet rapidly rising demand, remove inefficiencies, improve the quality of electricity supply, monitor domestic balance of payments, encourage foreign investments in electricity infrastructure and provide incentives for foreign investors to develop electricity system projects.

TABLE 1. RATIONALE FOR REFORMS IN MATURE MARKETS[a]

Objectives	AUL	NZE	UK	GFR	POL	LIT	USA	CHI	COL
Efficiency, costs and prices									
Improve productivity	√	√	√	√	√	√	√	√	√
Improve economic efficiency	√	√	√	√	√	√	√	√	√
Lower electricity prices	√	√	√	√	√	√	√	√	√
Improve labour productivity	√	√	√	√	√	√	√	√	√
Increase competition	√	√	√	√	√	√	√		
Provide customer choice	√	√	√	√	√	√	√	√[b]	√
Privatization	√		√		√	√	√	√	
Sustainability and reliability									
Promote demand side management	√	√	√	√	√	√	√		
Reduce environmental impacts		√		√	√	√			
Improve electricity supply reliability					√	√		√	√
Remove pricing anomalies					√				√
Investment and capital market									
Enhance investor confidence						√		√	√
Reduce government debt								√	
Free up scarce government resources	√					√	√	√	√
Encourage foreign investments						√		√	√
Develop capital market			√	√	√		√	√	
Social welfare									
Enhance affordability						√		√	

[a] AUL — Australia; NZE — New Zealand; UK — United Kingdom; GFR — Germany; POL — Poland; LIT — Lithuania; USA — United States of America; CHI — Chile; COL — Colombia.
[b] Oriented to large consumers (from 500 kW).

TABLE 2. RATIONALE FOR REFORMS IN TRANSITION AND POTENTIAL MARKETS[a]

Objectives	CPR	IND	INS	MAL	PHI	THA	PAK	SAF	TUR	KEN
Efficiency, costs and prices										
Improve productivity	√	√	√	√	√	√	√	√		√
Improve economic efficiency	√	√	√	√	√	√	√	√		√
Lower electricity prices	√	√	√	√	√	√	√			√
Improve labour productivity		√								
Increase competition	√	√		√		√			√	√
Provide customer choice		√	√	√	√	√			√	
Privatization		√	√	√	√	√	√		√	√
Sustainability and reliability										
Promote demand side management									√	
Reduce environmental impacts	√	√			√				√	
Improve electricity supply reliability	√	√		√	√		√			√
Remove pricing anomalies	√	√			√					√
Investment and capital market										
Enhance investor confidence		√	√		√		√		√	√
Reduce government debt		√				√	√		√	
Free up scarce government resources	√	√	√	√			√		√	√
Encourage foreign investments	√	√	√	√	√	√	√		√	√
Develop capital market						√				
Social welfare										
Accelerate electrification		√			√		√	√		√
Enhance affordability	√	√	√		√		√			√

[a] CPR — China; IND — India; INS — Indonesia; MAL — Malaysia; PHI — Philippines; THA — Thailand; PAK — Pakistan; SAF — South Africa; TUR — Turkey; KEN — Kenya.

3. ELECTRICITY MARKET REFORMS

3.1. INTRODUCTION

This section presents the salient features of electricity market reforms undertaken by various countries included in this report. The features include industry structure and ownership arrangements; regulatory arrangements, including network regulation, end users prices and special incentives; market mechanisms; and risk allocation.

3.2. MATURE MARKETS

3.2.1. Australia

Structure and ownership: A significant consolidation of the electricity industry was witnessed in the post-war years in the country. This consolidation resulted in the creation of vertically integrated, publicly owned electricity utilities. A process of internal reform — focusing mainly on improving the management and control arrangements — was undertaken in the mid- to late 1980s. The market reform of the electricity industry was initiated in the early 1990s. This led to the restructuring of the power sector. The former electricity authorities were gradually disaggregated into separated generation, transmission, distribution and retailing businesses. The national electricity market (NEM) was created as a wholesale market for electricity trading. It started operation in 1998, initially covering only two states (New South Wales and Victoria) and gradually extending to include six jurisdictions.

More than 300 generators operated in the NEM in 2013. The majority of generation companies in Victoria and South Australia are owned by private entities. The Tasmanian generation sector remains mostly in government hands. While public corporations control the majority of generation companies in New South Wales and Queensland, there has been steadily increasing private sector activity in these states. Besides, while governments had structurally disintegrated the electricity industry in the 1990s, there has been a trend towards vertical reintegration between retailers and generators recently. The privatization process in New South Wales (since 2011) and Queensland (since 2007) has somewhat reinforced this trend [22].

The NEM region is wholly interconnected. There are five state-based transmission companies that operate the regional networks and three companies that operate the interconnectors linking these regions. Besides, there are 13 major distribution companies, each of which is a monopoly service provider in a designated area. The transmission networks in Victoria and South Australia, and the three interconnectors are privately owned. Victoria's distribution companies are also privately owned, while the distribution network in South Australia is leased to private firms. Network companies in the Australian Capital Territory are jointly owned by the government and private entities. All network companies in Queensland, New South Wales and Tasmania are owned by the respective state governments [22].

Regulatory arrangements: The initial reform of the Australian electricity industry led to the development of complex regulatory arrangements involving a plethora of national and state regulators [10]. Since 2005, further reform has been undertaken to rationalize the regulation of the power sector. Currently, two intergovernmental bodies are responsible for determining the direction of Australia's energy policy at the national level: the Council of Australian Governments and the Ministerial Council on Energy.

At the administrative level, the responsibility for regulating the sector is mainly assumed by three agencies: the Australian Competition and Consumer Commission (ACCC), the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The ACCC enforces the Commonwealth competition, fair trading and consumer protection laws. These laws apply to all activities in the energy industry. The AEMC is mainly responsible for the rule making process under the National Electricity Law and for making determinations on proposed rules. The AER enforces the National Electricity Law and the National Electricity Rules, monitors the wholesale electricity markets and regulates the electricity transmission and distribution networks in the NEM. In 2012, the Retail Law established national regulation of the retail energy markets and transferred significant regulatory functions of the retail markets to the AER. The law commenced in Tasmania and the Australian Capital Territory on 2012-07-01, in South Australia on 2013-02-01 and in New South Wales on 2013-07-01. Victoria and Queensland are yet to implement the Retail Law [22]. The NEM is operated by the Australian Energy Market Operator (AEMO). Figure 1 shows the regulatory framework of the Australian electricity industry.

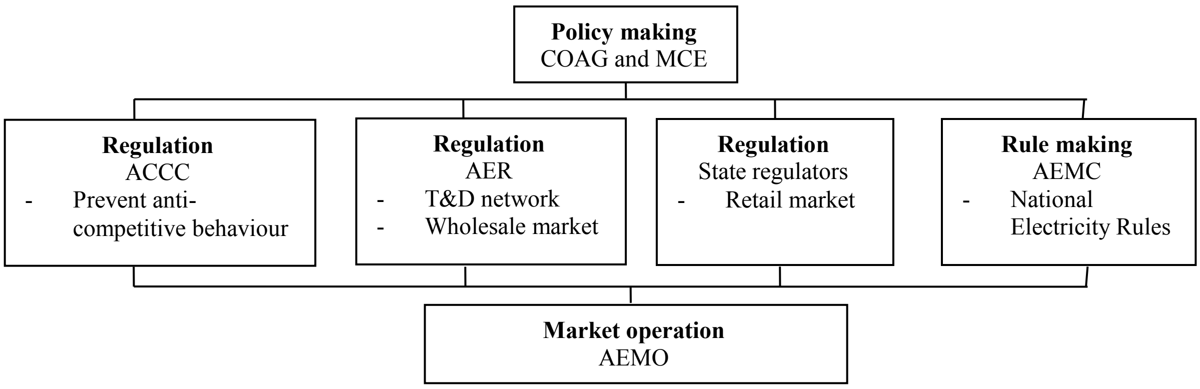

FIG. 1. The regulatory framework of the Australian electricity industry. (Note: COAG — Council of Australian Governments; MCE — Ministerial Council on Energy; ACCC — Australian Competition and Consumer Commission, AER — Australian Energy Regulator, T&D — transmission and distribution; AEMC — Australian Energy Market Commission; AEMO — Australian Energy Market Operator).

Network regulation: The ACCC was the industry regulator for transmission in the NEM until this role was transferred to the AER in 2005. But the ACCC still retains the role of enforcing the non-discriminatory access to electricity networks. The distribution networks were previously regulated by state and territory regulators. In 2008, the AER acquired the responsibility for regulating the electricity distribution businesses. Transmission and distribution companies must periodically apply to the AER to assess their revenue requirements (typically every five years). In the case of transmission, the AER must determine a cap on the maximum revenue that a network can earn during a regulatory period. The range of available control mechanisms is wider in distribution, but generally involves setting a ceiling on the revenues or prices that a network can earn or charge during a period [22].

Retail energy prices: All NEM jurisdictions except Tasmania have introduced full retail contestability in electricity. In July 2011, Tasmania extended contestability to customers using at least 50 MW·h. Full retail contestability is implemented in Tasmania since 2014. Different forms of retail electricity price regulation continue to apply in all jurisdictions except Victoria and South Australia. In general, the regulation applied on retail prices sets the prices for small customers under a standing contract if they do not have a market contract with an energy retailer [22].

Special incentives: At the national level, the Australian Government introduced a mandatory renewable energy target (MRET) scheme in 2001, to support the development of large scale electricity generation from renewable sources. Its initial target was set at 9500 GW·h. In 2009, the government extended the MRET to encourage the uptake of large scale renewable energy to a 20% share of electricity generation or 45 000 GW·h by 2020. The extended MRET also introduced special incentives for small scale renewable generation (e.g. rooftop solar photovoltaic installations) [22].

Further, the Australian Labour Government (2007–2013) introduced a price on CO_2 on 2012-07-01 as the central plank of its Clean Energy Future Plan. The plan targeted a reduction of CO_2 and other GHG emissions to at least 5% below 2000 levels by 2020 and a reduction of up to 25% with equivalent international action. The central mechanism placed a fixed price on CO_2, starting at Australian $23 per tonne of CO_2-equivalent emitted. An ETS was planned to replace the fixed price arrangement on 1 July 2015 [22]. However, the CO_2 pricing mechanism was abolished in 2014 by the Coalition Government elected in September 2013 as a fulfilment of the related campaign pledge.

At the state level, there also exist a number of measures adopted by state governments to reduce CO_2 emissions in the power sector, such as Queensland's 13% gas target, New South Wales's Greenhouse Gas Abatement Certificate scheme and the Solar Flagships programme.

Market mechanisms: The Australian wholesale market comprises a mandatory gross (spot) pool. All generators with a capacity greater than 30 MW compete by lodging bids to supply electricity to the pool on a half-hourly basis. Bids are ranked by the central grid operator (i.e. AEMO) and dispatched by regional centres based on an economic criterion. The pool (spot) price for any half hour is the price of the marginal generator scheduled, i.e. its short run marginal cost. All generators running during a particular half hour receive remuneration at the pool price for that half hour. Spot prices may differ across regions because of the limitations of network capacity and technology mix. The spot price in the NEM is capped at Australian $13 500 (value of lost load). There is also a minimum for the spot price: the market floor price. It is currently set at Australian $ 1000/MW·h [22]. The NEM is an energy only market meaning that all capacity in the market is remunerated through the market clearing process. No other payments are made in the market except those arising from specifically designed reliability safety nets and specific purpose ancillary services [23].

Risk allocation: The electricity market reform has gradually shifted the investment risk from customers to investors. Market participants (generators and retailers) manage their risk by entering into hedge contracts with each other on the OTC markets or through futures markets (the Sydney Futures Exchange). But increasingly retailers and generators are bypassing these markets and are managing spot price risks through vertical integration instead. OTC markets comprise direct transactions between two counterparties. On the Sydney Futures Exchange, standardized and centrally cleared financial contracts — Australian Electricity Futures and Options — are traded. They are structured as cash settled contract for difference (CFD) against the New South Wales, Victoria, Queensland and South Australian regional reference nodes in the NEM [24].

3.2.2. New Zealand

Structure and ownership: Prior to the restructuring, there were two organizational tiers in the electricity sector: the New Zealand Electricity Department (NZED), a government department controlling large generation and the high voltage transmission grid; and a large number of Electricity Supply Authorities running low voltage distribution networks bundled with retail energy sales. A limited number of large industrial customers took supply directly from the grid. All other final purchasers were customers of the local franchise monopoly (the Electricity Supply Authority).

The market reform of the New Zealand electricity industry began in the late 1980s. The NZED was first corporatized as the Electricity Corporation of New Zealand in 1987. In 1994, transmission assets were further unbundled from the Electricity Corporation to form Transpower, an independent, state-owned transmission company. In the following years, the remaining generation assets of the Electricity Corporation were split into five separate generation companies. All distribution companies were corporatized in 1992. Retail franchises were abolished and retail operators separated from line networks.

Currently, the generation segment is made up of five major companies, including Contact Energy, Genesis Power, Meridian Energy, Mighty River Power and TrustPower. They produce more than 90% of the country's electricity [25]. Two of these, Contact Energy and TrustPower, are publicly listed companies. The other three are state-owned enterprises. Electricity is distributed throughout New Zealand by 29 distribution companies. Some of the largest distribution network owners are publicly listed, but most are trusts or other local bodies. Most of the retailers in the country are vertically integrated with the five largest generation companies.

Regulatory arrangements: The New Zealand electricity industry was self-regulated until 2004 when it began operating under the Electricity Governance Rules and the Electricity Governance Regulations, overseen by the Electricity Commission. A Ministerial Review in 2009 tightened the focus on market performance and — through the Electricity Industry Act 2010 — provided for the electricity market to be governed by the Electricity Industry Participation Code, overseen by the Electricity Authority.

The Commerce Commission is New Zealand's primary competition and economic regulatory agency. It is an independent Crown entity established under Section 8 of the Commerce Act 1986, and its purpose is to achieve the best possible outcomes from uncompetitive and regulated markets for the long term benefit of New Zealand. It regulates the revenue of electricity transmission and distribution networks, as well as gas pipelines, airports, telecommunications and the dairy industry.

Besides, the Ministry of Economic Development is responsible for developing and implementing the electricity sector policy, particularly relating to governance and market structure. The ministry also monitors market performance, including competition issues and electricity prices.

Network regulation: The Commerce Commission is responsible for regulating the pricing of electricity network companies (transmission and distribution). An individual revenue cap regulation is applied by the Commerce Commission to Transpower since 2011. This rule replaced the earlier administrative settlement that placed a cap on the revenue for all regulated line services. Distribution prices are regulated under the Commerce Act 1986 that requires all distribution companies to comply with the price–quality path set by the Commerce

Commission. This price path places upper limits on the allowable revenue distribution companies may earn in a given year.

Retail energy prices: New Zealand was one of the first countries to introduce retail competition for all groups of consumers. Small consumers became contestable in 1994. There is no explicit regulation of retail pricing. Consumers contract with retailers for electricity supply or purchase directly from the wholesale electricity market. The contracts offered by retailers to end users normally include the cost of electricity supplied to the consumers and charges for line services. Some large consumers contract separately with retailers and line companies for electricity and network services. Virtually all contracts offered by retailers to household and small business consumers contain a fixed daily rate and a charge depending on electricity usage [26].

Special incentives: Explicit support schemes for renewable energy are minimal in New Zealand. Most renewable electricity projects rely on existing market mechanisms while some technologies such as solar water heating receive low levels of government support.

Market mechanisms: The spot market for real time electricity delivery is a voluntary pool market. It is an energy only market with no additional capacity payments to generators. Generators that are bigger than 10 MW or are grid connected compete in the spot market for the right to generate electricity to satisfy demand, while retailers and large offtake customers submit bids for electricity demand. Nodal pricing is used because it incorporates the cost variation of electricity transmission owing to location, outages and constraints. A half-hourly instantaneous reserve market is also operated alongside the energy market to ensure that enough backup generation (or, alternatively, load reduction) is available should the largest generator unexpectedly fail.

Risk allocation: The market reform in the power sector has resulted in the reallocation of the investment risks from the customers to the investors. Traditionally, market participants hedged the price risks through the OTC market, where buyers negotiate directly with sellers to agree on a price. These contracts can be customized and offer flexibility for both parties. Energy Hedge is a web-based hedge market. It was established in 2004 and is used by the five largest generators as a trading platform for more standardized OTC contracts. Recently, buyers and sellers of electricity have been able to contract on the futures market operated by the Australian Stock Exchange. These contracts are standardized and are structured as cash settled CFD against two grid reference nodes (Otahuhu and Benmore) in the electricity market. Besides, the five largest generators are also vertically integrated with retailers. One of the reasons for this is to hedge against the risk of price volatility.

3.2.3. UK

Structure and ownership: The electricity industry in England and Wales was restructured in the 1990s. The former vertically integrated electric utility with its 74 power stations and the National Grid, the Central Electricity Generation Board was divided into four companies. Sixty per cent of the conventional generating capacity was placed in National Power and the remainder in Power Gen. A single company was created to take over all the NPPs, and later split into British Energy and Magnox Electric. The high voltage grid was transferred to the National Grid. Twelve regional electricity companies assumed the responsibility for electricity distribution [27].

In England and Wales, most of the generation and regional distribution companies were privatized in 1990. The more modern advanced gas cooled and pressurized water nuclear power stations were privatized as British Energy in 1996, while the older nuclear stations (Magnox) remained state-owned and in 2008 they were transferred to the Nuclear Decommissioning Agency. In 2004, British Energy ran into financial difficulties and had to apply for state aid. In 2009, it was relaunched as an independent company, merging with EDF Energy that allocated 20% of British Energy's shares and output to Centrica shortly thereafter.

In Scotland, two private companies emerged that were vertically integrated across all supply chain activities. At first, the state-owned company Scottish Nuclear operated all nuclear power stations in Scotland, but it was later split between British Energy and Magnox Electric.

During the 1990s, many new generators entered the market in England and Wales (many built or commissioned by the regional electricity companies) and the established fossil fuel generators merged with regional electricity companies. Scotland joined this market in 2005. As of 2005, six vertically integrated companies are responsible for a large share of generation and for nearly all supply to household customers. The two Scottish companies also own transmission and distribution networks. The National Grid remains responsible for the transmission network in England and Wales and for system operation throughout Great Britain. Table 3 shows the main activities of the six vertically integrated firms.

TABLE 3. THE MAIN VERTICALLY INTEGRATED FIRMS IN THE UK ELECTRICITY INDUSTRY

Company name	Generation	Supply	Transmission	Distribution
Centrica (BG)	√	√		
EDF Energy	√	√		*
E.ON UK	√	√		*
RWENpower	√	√		
Scottish Power	√	√	√	√
Scottish and Southern Energy	√	√	√	√

* Distribution assets for these two companies were sold in 2010 and 2011, respectively.

Regulatory arrangements: The Office of Gas and Electricity Markets (Ofgem) regulates the gas and electricity networks and the competitive wholesale and retail markets in the gas and electricity sectors.

Network regulation: Third party access is a key feature of the liberalized market, whereby transmission and distribution operators are required to connect all new generators and consumers for a certain connection fee (the costs of the assets required for the connection) and for a use of system charge (to remain connected). Ofgem regulates transmission and distribution companies and is responsible for controlling transmission and distribution prices. The price control takes the form of a price cap based on the retail price index minus efficiency savings. It sets the maximum amount of revenue for the network companies to enable them to recover their costs and earn a return in line with agreed expectations. Ofgem recently announced the implementation of the 'revenue incentives innovation outputs' scheme, a new version of the price cap, intended to tie regulated revenues to specific outputs and innovations where companies can demonstrate benefits for their consumers.

Retail energy prices: Competition in retail supply was introduced by a phased opening process, initially for customers with consumption above 1 MW in 1990, with 100 kilowatt (kW) in 1994, and for all consumers in 1999. Price control remained in place in the form of default tariffs available to all customers until April 2002, even after the market was liberalized [28]. Under current arrangements, suppliers' behaviour is constrained in some key areas by, for example, disallowing price discrimination (i.e. charging higher prices in their former franchises and lower in others). In 2010, Ofgem launched the Retail Market Review in response to growing social concerns that the energy market was not working effectively for consumers. This review resulted in further reforms of the retail energy market and reduced the complexity of retail tariffs [29].

Special incentives: Initially, a non-fossil fuel obligation was imposed on distribution companies to purchase electricity from nuclear and renewable generation. It was replaced by the renewable obligation scheme in 2002. Under this scheme, suppliers are required to secure a specified share of electricity from renewable sources or pay a penalty price. Different types of renewable energy technologies receive different levels of support. For example, until 2013, onshore wind received 1 renewable obligation certificate (ROC) per MW·h generated, while offshore wind receives 2 ROCs for the same amount until 2015 [30].

In 2009, a growing public concern over energy security was witnessed in the UK due to ambitious targets for GHG emissions reductions, increasing gas import dependence and the closure of ageing power plants. In response to this concern, Ofgem launched a review of the capability of current market and regulatory arrangements to deliver secure and sustainable energy supplies. This resulted in the publication of the Planning our Electric Future: a White Paper for Secure, Affordable, and Low-carbon Electricity by the British government in 2011. The white paper outlined the government's plan to further reform the electricity industry to ensure secure and low carbon electricity supplies. This plan has two key mechanisms: a CFD FIT scheme and a capacity market [30].

The CFD FIT scheme is a long term contract for stabilizing revenues and reducing risks to support investments in all forms of low carbon electricity generation, including nuclear power. If the wholesale electricity price is below the price agreed in the contract, the generator will receive a top-up payment to make up the difference. If the wholesale price is above the contract price, the generator will pay the surplus back [30].

The capacity mechanism is based on centralized supply contract auctions. It is aimed to ensure sufficient, reliable and diverse generating capacity to meet demand as the amount of intermittent and inflexible low carbon generation increases [30].

Market mechanisms: The Electricity Pool ran from 1990 to 2001. It set a single price for each half hour interval of the following day, based on forecast generation and demand volumes. The price was set by the marginal (i.e. highest cost) generator in a least cost production schedule with a markup related to the loss of load probability (LOLP). When forecast volumes differed from actual, the system operator took action to balance the system at the generators' offer prices. This service, along with the markup for LOLP, provided generators with some additional revenue.

The system was replaced in 2001 by the New Electricity Trading Arrangements (NETA) under which market participants, i.e. generators, suppliers and traders, enter into contracts to buy and sell certain quantities of energy, a record of which is submitted to the settlement system. (For a full description of the electricity wholesale market under NETA, see Ref. [31].) If contractual volumes differ from actual outputs or consumption, the Great Britain System

Operator balances the system in the half hour before delivery, arranging withdrawals from and injections into the system based on the bid and offer prices submitted by participants. Outstanding imbalances are settled at penalty prices in order to incentivize accurate forecasting of available and required energy.[1] In 2005, Scotland was included in the England and Wales arrangements, creating the British Electricity Trading and Transmission Arrangements (BETTA). Three power exchanges, the APX, the N2EX and the Intercontinental Exchange are now operating in the UK.

Risk allocation: While some customers were still subject to a retail monopoly, suppliers who entered into long term PPAs were able to pass on the market risks to consumers. Once the monopoly ended, the NETA encouraged vertical integration and diversification so that most risk is held by the six or seven large companies. The investment risks in competitive generation markets are borne by the investor, although renewable energy sources receive a premium as they earn income from the sale of ROCs to suppliers who are obligated to acquire them. However, the price of ROCs varies as the renewable energy production varies, exposing investors to some risk. The UK government introduced FITs partly to reduce risks to the investors by offering fixed prices.

3.2.4. Germany

Structure and ownership: The German electricity wholesale market is dominated by four major utilities: E.ON, RWE, EnBW and Vattenfall Europe. However, the closure of eight NPPs in 2011 has significantly reduced their market share. In addition, these four utilities also need to compete with large volumes of renewable energy, most of which lies outside the market [32].

In the retail segment, the market share of these four utilities continues to fall. The regulators reported that the combined retail market share of these four utilities was 45% in 2011, compared to 50% in 2008. The remainder of the retail market comprises about 900 municipal utilities acting as suppliers [32].

There is no single national transmission system operator (TSO). The four TSOs were previously owned by one of the four utilities. However, there have been a number of changes in the ownership structure in recent years as the big utilities divested transmission assets for a number of reasons, including regulatory pressure following initiatives taken by the European Commission and the Federal Cartel Office (Bundeskartellamt) and the need to strengthen company balance sheets. This resulted in the sale of assets to independent shareholders or legal unbundling from the parent company [32].

Regional or local distribution networks are operated by a large number of vertically integrated utilities that own generation assets as well as distribution businesses. The four large utilities usually hold shares in these distribution system operators [32].

Regulatory arrangements: The Federal Ministry of Economics and Technology (BMWi) is the leading agency responsible for energy policy. The Federal Cartel Office has primary responsibility for the practical implementation and enforcement of the Electricity Act against Restraints of Competition at the federal level, i.e. involving more than one federal state. It is

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[1] Market participants submit both a statement of their contract position and a forecast of their actual generation and consumption. Strictly speaking, the system operator reacts to errors in the latter. However, the settlement system recognizes only changes relative to each market participant's contract position.

also responsible for the review of the competition effects of mergers and for the prohibition of cartels but it does not decide on policies. Individual states have energy sector supervisory agencies that implement federal law, including maximum electricity prices to small consumers. The states also have cartel offices that are responsible for competition cases restricted to a single state. The Monopoly Commission advises the government on antitrust and competition issues, makes recommendations on major merger and acquisition cases if a ministerial authorization is requested, and comments on topical antitrust policy matters. It also compiles a major biannual report on these issues. The Federal Network Agency (Bundesnetzagentur) was created as the federal electricity regulator in 2005. It is responsible for all network operators with more than 100 000 customers. The federal states are in charge of regulating smaller network operators [33].

Network regulation: Until 2008, the German transmission and distribution companies were regulated according to the 'cost of service' principle. A revenue cap regulation was introduced in 2009 to control the network tariffs [32].

Retail energy prices: Germany started a full market opening without any restructuring in 1998. The electricity sector was then characterized by a high degree of vertical and horizontal integration and was dominated by a few large companies. This structure and the congestion of the interconnected transmission networks were argued at the time to be the major hindrances to the development of effective competition. The electricity prices for household consumers were regulated until July 2007. Since then, consumers have the option of staying with their default power suppliers or switching to other electricity suppliers. In 2013, a significant proportion of household consumers were still with their original suppliers [32].

Special incentives: Renewable energy was promoted by a special feed-in law that guaranteed high prices for qualifying renewable energy sources while at the same time guaranteed the sale of renewable electricity produced [34].

Market mechanisms: Market participants can buy and sell electricity in two major power exchange markets: the European Energy Exchange and the European Power Exchange. The former offers electricity products for futures trading while the latter offers electricity products for spot market trading. In addition, there are substantial bilateral trading opportunities for the main utilities. The volume of bilateral trading is several times higher than that on the exchange [32].

Risk allocation: With the introduction of market reforms, investment risks in the power sector have been transferred from the customers to the investors. Several measures are used by investors to mitigate the risks, including OTC trading, energy derivatives and vertical integration.

3.2.5. Lithuania

Structure and ownership: Prior to the reform, the electricity industry comprised of two main entities: a state-owned vertically integrated utility (JSC Lithuanian Power) and a state-owned nuclear power company. In 2010, in response to the third energy package of the EU, the electricity law was amended that resulted in the restructuring of the electricity industry [35]. JSC Lithuanian Power was unbundled into several companies, including a transmission company (JSC Litgrid), a market operator (JSC Baltpool) and an independent power supplier (JSC Energy Supply). JSC Litgrid is the TSO. It is responsible for electricity planning, dispatch control and operational planning. JSC Baltpool is the market operator for wholesale electricity trade and it regulates the activities of the electricity exchange.[2]

JSC Lithuanian Power has six wholly owned subsidiaries.[3] The company has the majority of votes in Gotlitas UAB and it also has a majority holding in Baltpool UAB through LITGRID UAB. The electricity market structure and the new players in the electricity market are presented in Fig. 2.

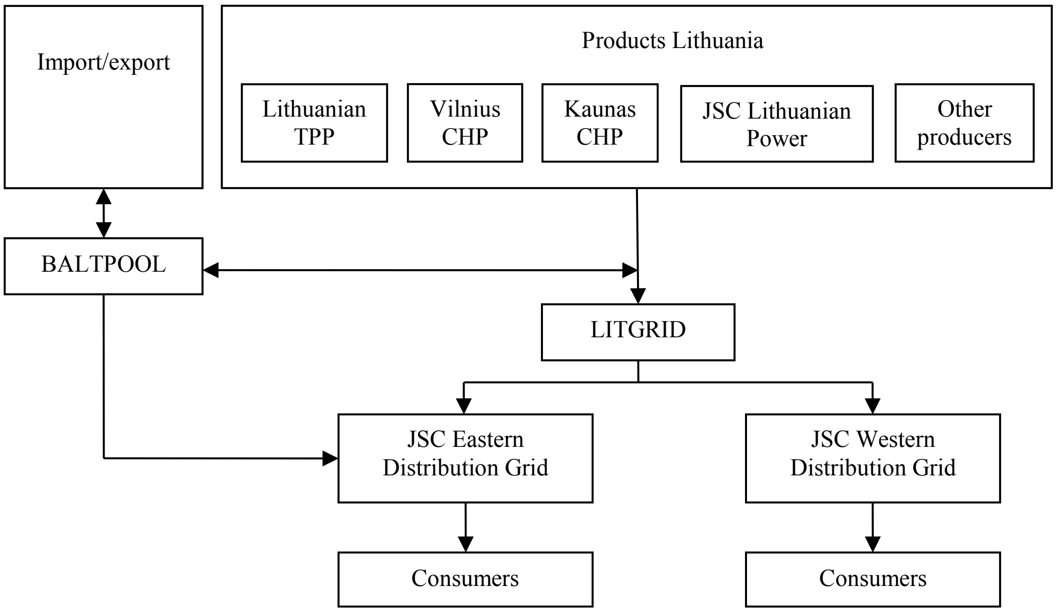

FIG. 2. Electricity Market Model in Lithuania after January 2010. (Note: TPP — thermal power plant; CHP — combined heat and power).

Regulatory arrangements

Network regulation: Under Article 40 of the Lithuanian Electricity Law[4], arrangements for gradual third party access to eligible customers and direct power supply contracts with freely selected independent suppliers were established. Under the regulated third party access market structure, the transmission company publishes transmission tariffs and access requirements, and the generators enter into an agreement with eligible customers who can directly negotiate with the generators. Under this arrangement, the remaining customers are charged a cost-based rate by the regulator according to an assumed optimal operation.

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[2] The company was established in compliance with the Electricity Market Development Plan approved by the Government of the Republic of Lithuania on July 8, 2009 to implement measures for the creation of a common electricity market of the Baltic States following the principles and experience of the electricity market of the Nordic countries (Nord Pool) [36].

[3] The subsidiaries are: Energetikos Pajegos UAB, Kauno Energetikos Remontas UAB, Kruonio Investicijos UAB, Litgrid UAB, Energijos Tiekimas UAB, InterLinks UAB and Vsl Respublikinis energetiku mokymo centras.

[4] Official Gazette No. 66-1984, 2004

Retail energy prices: The National Control Commission for Prices and Energy (NCCPE) regulates electricity prices by setting price caps for a three year regulatory period subject to annual revisions according to changes in the forecasting data by the NCCPE. These changes can be due to electricity volume, annual inflation rate, taxes payable by the service provider and other factors beyond the control of the service provider [35], [36]. After 2010-01-01, regulated tariffs were removed for large consumers (about 35% of the nationl demand). Since 2015-01-01, regulated supply tariffs for all consumers are abolished, except the guaranteed tariffs for groups designated by EU regulations. Despite full retail competition, only a few large consumers have switched their suppliers.

Market mechanisms: The Power Exchange started operating on 2010-01-01. The Lithuanian market is based on the same principles as the Nordic power market for wholesale trading where price and flow are calculated simultaneously to increase market efficiency (implicit auction). Electricity is traded through bilateral contracts (local contracts) or via the Power Exchange. A bilateral contract is an agreement between an energy consumer and an energy supplier to buy and sell a specified quantity of energy at a specific price. All imported or exported energy is traded via the Power Exchange. The average daily (or monthly) wholesale price of electricity at the Lithuanian Power Exchange is usually lower than the regulated price of electricity, but peak time prices are higher. The Power Exchange has been operating for too short a period to track consistent tendencies or draw conclusions about its effectiveness.

Risk allocation: The investment risks of generation technologies are based on the investor's expectations of future electricity prices and how much of the risks can be shared and passed on to future consumers. The potential high returns and long term contracts may lead to reduced uncertainty and risks.

3.2.6. Poland

Structure and ownership: The restructuring of the Polish power sector began in the 1990s. Presently, the Polish electricity industry comprises the TSO (PSE-Operator) and four major power groups (PGE, Tauron, Enea and Energa) encompassing generation, distribution and trading companies. There also exist some private electricity generation and trading companies. For example, RWE owns a distribution company (Stoen), GdF Sueze owns a power station (Polaniec) and EdF also owns a power station in Rybnik. Vattenfall has recently made a decision to withdraw its resources from Poland.

Most of the power companies are listed on the stock exchange with the majority of shares being held by the State Treasury. For example, the State Treasury owns 100% of stakes of PSE Operator and more than 50% of the shares in each of the generating companies (see Table 4).

TABLE 4. OWNERSHIP STRUCTURE OF THE POLISH POWER COMPANIES

Energy capital group	Share of the State Treasury in the ownership mix (%)
PGE	70
Tauron	60
Enea	52
Energa	51

Regulatory arrangements

Network regulation: The electricity market is based on regulated third party access. All suppliers and consumers have legally guaranteed access to the grid. Producers of electricity from renewable sources and cogeneration are given priority in dispatching in order to lower their investment risks. This is in accordance with the overall policy to promote renewable and cogeneration technologies. The Energy Law requires the regulation of prices for transmission and distribution related services and for household consumers.

Retail energy prices: According to the Energy Law, the prices for grid related services and the purchase of electricity (energy) by households are regulated. All other prices are set on the competitive market. The structure of prices of electricity supply for final consumers reflects the cost mix in the Polish power system (see Table 5).

TABLE 5. INDICATIVE ELECTRICITY PRICE STRUCTURE (%)

Overall		Tariff groups							
		A (HV[a])		B (MV[b])		C (LV[c] business)		G (households)	
Energy fee	T&D[d] fee	Energy fee	T&D fee	Energy fee	T&D fee	Energy fee	T&D fee	Energy fee	T&D fee
49	51	62	38	55	45	41	59	45	55

[a] HV: high voltage
[b] MV: medium voltage
[c] LV: low voltage
[d] T&D: transmission and distribution

Special incentives: The law obliges electricity suppliers (generators and traders) selling electricity to final consumers to possess certificates: green for electricity produced by renewable sources, red for electricity produced by cogeneration and yellow for electricity produced by cogenerating plants fired with gas. The share of the total amount of electricity sold to final consumers labelled by certificates is defined by law each year. The certificates are issued and redeemed by the energy regulator. Each company generating labelled electricity can obtain revenues from the sale of certificates on the competitive market or to the

Last Resort (Default) Suppliers who are legally obliged to buy that electricity in the offered amount at the average last year market price. If a supplier is not able to fulfil the legal obligation on the possession of certificates, it has to pay a fee to the Environment Protection Fund. The fee level is defined by the Energy Law.

Market mechanisms: The electricity market consists of three segments: bilateral contracts between sellers (producers or trading companies) and consumers, transactions on the energy commodity exchange and on electricity trading platforms, and the balancing market managed by the TSO. The energy exchange is a supplement of the bilateral contracts segment that enables entities dealing with energy trade to adjust their own contract obligations to current demand by purchasing the lacking amounts of electricity or selling the surplus. Thus the balancing market is matching the supply and demand of electricity on-line and manages congestions to ensure the required quality parameters in electricity supply (stability of the system and voltage levels at nodes of the grid). Minimizing the cost of satisfying demand according to market principles across the whole system (the 'copper plate' principle) is the main criterion for the functioning of the balancing market. Figure 3 shows the evolution of the Polish electricity market since the early 1990s.

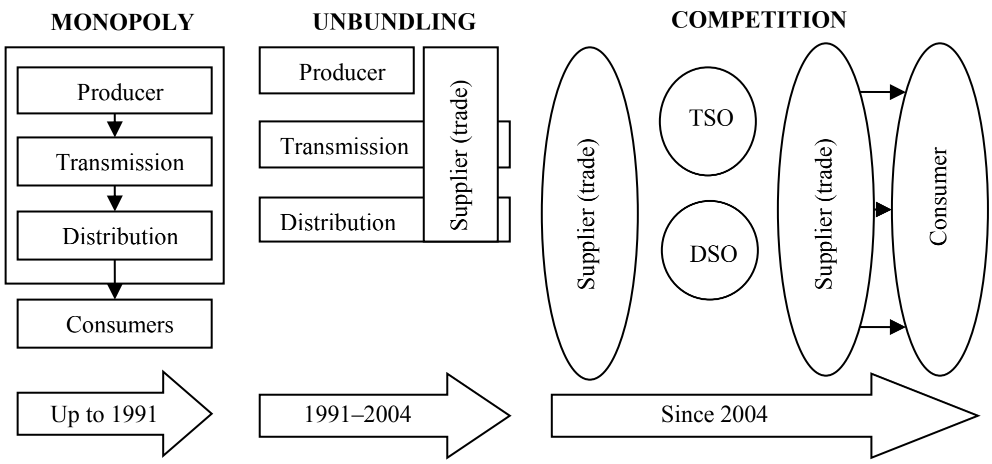

FIG. 3. Electricity market reform in Poland. (Note: TSO — transmission system operator, DSO — distribution system operator).

Risk allocation: Market related risks are allocated among all market players. The largest risk is borne by electricity producers based on coal and lignite because of the uncertainties about the costs of CO_2 emissions allowances. Investors in gas fired plants also bear this risk in the future together with the risks of fluctuating gas prices in international markets. Tax payers are also exposed to the environmental risks because all costs related to more stringent environmental requirements are borne by final energy consumers who pay environmental fees that can be considered as a kind of tax.

3.2.7. USA

Structure and ownership: The institutional structure of the US electricity industry is complex and fragmented, with relatively little governmental presence (apart from dominance in two regions). Less than half of the investor-owned utilities are traditional vertically integrated utilities, owning transmission and distribution, while three quarters of the publicly owned or cooperative utilities are only involved in retail distribution. Retail sales are dominated by investor-owned utilities accounting for more than two thirds of sales to final customers, while wholesale power purchases are primarily undertaken by power marketeers and energy service providers. IPPs tend to sell at the wholesale level and they are virtually absent from retail markets. Net generation is dominated by traditional utilities accounting for 60% of generation by volume, while IPPs account for 31% [37].

Regulatory arrangements: The Federal Energy Regulatory Commission has broad authority under various federal acts to regulate the interstate electricity market, most notably wholesale (business–to–business) transactions. It is also responsible for ensuring non-discriminatory access to transmission. Distribution access is largely the responsibility of the states [37].

Network regulation: Transmission systems are traditionally operated by vertically integrated utilities. As a response to Order 2000, some transmission companies voluntarily transferred their responsibility for transmission system operation to independent operating entities known as regional transmission operators. They are responsible for electricity market operation, transmission tariff administration and network investment planning. Accordingly, the transmission systems are operated by either regional operators or vertically integrated utilities [37] and [38]. In regions where the electricity sector is still operated under a regulated regime, transmission tariffs are usually set according to the 'cost of service' principle, and the transmission expansion is planned by the federal states [38] and [39].

Retail energy prices: Sixteen states and the District of Columbia have introduced competition in retail markets for all customer classes [40]. The California electricity crisis in 2001 has had profound influence on the electricity reform. Since the onset of the crisis, no state has announced any plan to reform the electricity sector and a number of states have halted their reform programmes. There are a few states that even reversed the reform process with the reintroduction of regulated pricing for wholesale and retail electricity [41].

Market mechanisms: There are four active regional electricity markets: (1) New England (including the deregulated states of Connecticut, Maine, New Hampshire, Rhode Island, and the regulated states of Massachusetts and Vermont); (2) New York (involving only the state of New York); (3) PJM Interconnection (originally Pennsylvania, New Jersey and Maryland, now including markets in the deregulated states of Delaware, District of Colombia, Illinois, Michigan and Ohio, and in some markets in the regulated states of Indiana, Kentucky, North Carolina, Virginia and West Virginia); and (4) the Electric Reliability Council of Texas (involving primarily the state of Texas).

Risk allocation: With the introduction of the market reforms, investment risks in the power sector have been transferred from the customers to the investors. Several measures are used by investors to mitigate risks, including OTC trading, energy derivatives and vertical integration.

3.2.8. Chile

Structure and ownership: A programme of electricity market reform was initiated in 1978 with the creation of a partial vertically disintegrated power system and a wholesale electricity trading mechanism. Endesa, a state-owned company established in 1944 with extensive generation, transmission and distribution assets across the country, was split into 14 companies. These included six generation companies (including Endesa and Colbun), six distribution companies and two small isolated companies in the south providing generation and distribution services. Chilectra was separated into three companies including a generation company (Gener) and two distribution companies.

Presently, the electricity system is 100% privately owned. The government has a supervisory and regulatory role through the National Energy Commission (CNE) and the Superintendence of Electricity and Fuels. The generation segment is dominated by Endesa, Colbun, Gener (AES) and Suez. The largest provider of transmission grid services is Transelec. The main distributors are Chilectra, CGE Distribution, Chilquinta Energy and SAESA. Figure 4 shows the structure of the Chilean electricity industry.

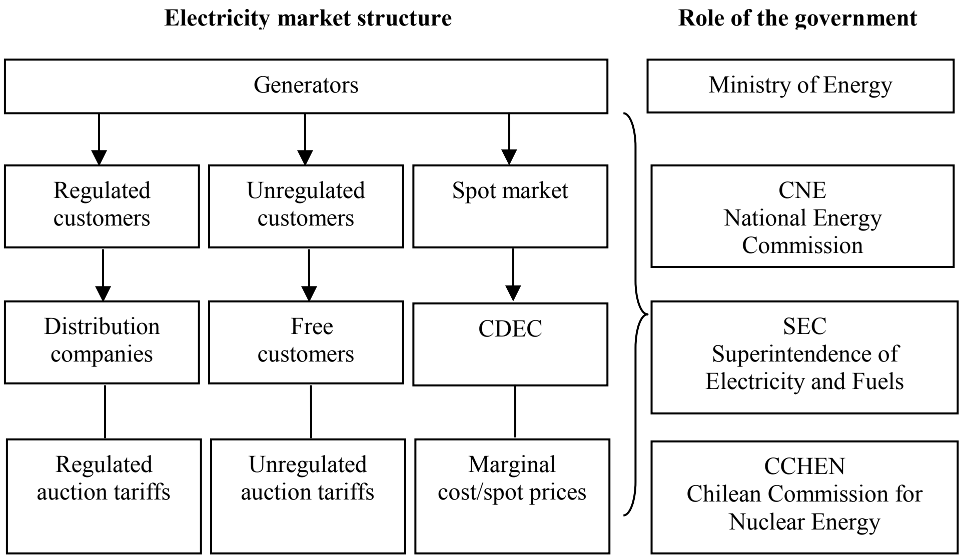

FIG. 4. Chilean electricity market structure. (Note: CDEC — Center for Economic Load Dispatch).

Regulatory arrangements: There are four organizations that oversee the working of the Chilean electricity industry: the Ministry of Energy, the CNE, the Superintendence of Electricity and Fuels and the Chilean Nuclear Energy Commission.

The Ministry of Energy was created in 2010 with the mandate to develop and coordinate plans, policies and standards for the operation and development of the sector, ensuring compliance and to advise the government on all matters relating to energy. The CNE has four main roles: assess energy issues and propose regulations, determine regulated prices, provide technical advice to the government and oversee the sector technically. Yet it has no power to enforce compliance. The Superintendence of Electricity and Fuels is an independent supervisory agency that reports directly to the president. It collects data to foster enforcement and regulation, to handle customer complaints, to verify compliance with service quality standards and investigate the causes of outages, and to impose service quality fines and customer compensations. The Chilean Nuclear Energy Commission is in charge of regulation, control and supervision of nuclear energy. It gives advice to the government on all affairs related to nuclear energy and proposes national plans for research, development, use and control of nuclear energy in all its aspects.

Network regulation: The regulation of non-discriminatory three party access to the network is in place. Network operators are required to provide connection to any generator who has complied with current regulations, including environmental, technical and construction standards.

Retail energy prices: End user prices comprise of regulated distribution charges, a wholesale price and relevant transmission charges. However, the regulation allows consumers with installed power of more than 500 kW to choose the category of tariff (free or regulated).

Special incentives: The Non-Conventional Renewable Energy Law was enacted on 2008-04-01. This law aims to fulfil the country's future energy requirements by developing non-conventional renewable energy sources, such as geothermal, wind, solar, tidal, biomass and small hydropower. The law requires power suppliers to procure a certain percentage of their total electricity supply from non-conventional renewable sources. Initially, the quota was set at 5%. Starting in 2015, the quota increases by 0.5% annually, reaching 10% in 2024.

Market mechanisms: The market is structured into three price categories: spot (generators), free (large consumers) and regulated (all but large consumers) prices.

Spot market (spot price): in this regime, dispatch is mandatory whenever the plant is available and the Center for Economic Load Dispatch commands it to start operating. This implies that dispatch is independent of the contracts of the generating companies. Companies that sell more energy than they produce are required to buy the difference in the spot market at the spot price.

Regulated market (node price): Regulated prices are paid by residential and other small consumers with less than 2 MW of consumption. These prices are calculated every six months by the CNE and they correspond to the expected marginal costs averaged over the next 24 to 48 months. The node price remains fixed for a six month period independent of demand and supply conditions. According to the legal modification in 2005, regulated prices are determined by a long term public tender process. In the regulated retail market, the generation companies sell energy to distributors, through long term contracts at regulated bid-based long term nodal prices set by the CNE. For contracts signed before 2005, energy sale prices were based on the so-called short term node prices. Long term node prices include indexation formulas that incorporate aspects such as the US inflation index, fuel price indices (mainly for diesel and coal) and indexation to energy prices in the spot market.

Free market: Free clients with a connected capacity of more than 2 MW, face a free market where they can negotiate energy contracts directly with the generating companies. These contracts establish supply conditions, reliability and prices. While a significant fraction of these contracts are closed at prices reflecting the supply conditions only in the long run, contracts can be freely renegotiated during a supply restriction. If the spot price of electricity climbs above the user's valuation of electricity, it seems natural to expect that the generating company and the user will undertake a mutually advantageous renegotiation.

Users with connected capacities between 500 and 2000 kW may choose between the free price and the long term node price regimes, with a minimum permanency period of four years in each regime. Prices negotiated with non-regulated customers usually include mechanisms to share the risks with other generation companies through indexation formulas for fuel prices, spot prices or other variables that reflect the actual supply costs of a generation company.

Risk allocation: A new regulatory model was implemented by incorporating a real market signal in consumer prices through auction mechanism in 2005. Distributors auction their demand at any time depending on their needs and also design their mechanisms and contracts depending on their own criteria, thus the current regulation implies that all proposed mechanisms and contracts must be revised and ultimately approved by the regulator before the auction occurs. An immediate consequence of this high degree of decentralization is that contracts cannot be standardized, hence a variety of contracts are offered in the market [42].

3.2.9. Colombia

Structure and ownership: Colombia has 48 registered electricity producers. Two public companies (Empresas Publicas de Medellin and Isagen) and a private company (Emgesa) control more than a half of the total generation capacity. Transmission in the national interconnected system is carried out by nine companies, four of which are exclusively transmission firms and one of them, ISA, owns 75% of the transmission assets. The rest are integrated companies performing various types of activities in the electricity chain. There are 30 distribution and commercialization companies (eight of them integrate generation, distribution and commercialization, and three are fully integrated) and 55 retail companies. The four largest players in the retail market are the Empresas Publicas de Medellin with a market share of 26.5%, Codensa (Endesa in Bogota) with 22%, the International Natural Gas Group (formerly Electrocosta and Electrocaribe) with 21.2% and the National Group with a 14.6% share.

Regulatory arrangements: The Ministry of Mines and Energy is the industry's governing body that takes part in the operation and planning of Colombia's electric power industry. The Mining Energy Planning Unit prepares the generation expansion plan (not mandatory) and the transmission expansion plan (mandatory). The Regulatory Commission for Gas and Energy, comprising five independent experts and three ministers, is responsible for regulating the gas and electricity markets. This commission sets the tariff structures and guarantees network access, determines transmission charges and standards for the wholesale market, and guarantees the quality and reliability of the service. The independent Superintendence for Residential Public Services is charged with overseeing the system, and identifying and sanctioning abuse of market power. XM (Compania de Expertos en Mercados), a public utility of the ISA group, is in charge of power system operation and power market administration. It assumed responsibilities of the former system operator of the national interconnected system and of the former power exchange. The National Operation Council is the consultation body for market operation and the Marketing Advisory Committee is the monitoring body for commercial exchange system and retail activities.

Market mechanisms: The Colombian wholesale power market involves agents authorized by law to participate as buyers and sellers in economic activities central to the electricity industry such as generation (compulsory above 20 MW, optional between 10 and 20 MW). Currently the market structure comprises the following four components: (i) a physical delivery day-ahead spot market (hourly basis); (ii) a firm energy market for generation capacity adequacy; (iii) a non-standard bilateral contract market (tailor made cash settled contracts); and (iv) a secondary market for ancillary services.

Consumers are divided into regulated and non-regulated categories. A 0.1 MW of peak demand or 55 MW·h/month of energy consumption is the threshold limit to be considered a regulated user. Non-regulated users are allowed to choose their retail supplier in order to negotiate their electricity prices with generators in the bilateral contract market.

There is no restriction on the time horizon for bilateral contracts. The degree of exposure in the free market is the decision of the marketing agents and generators. However, initially there were rules that required marketeers serving regulated users to cover a minimum percentage of their power requirements through bilateral contracts with other agents. These requirements were gradually dismantled and disappeared completely at the end of 1999 [43].

Risk allocation: Several instruments have been designed to enable producers to manage risks and to incentivize investments in generation assets. Initially, several power producers (mainly thermal plants) entered the market by using PPAs, a long term contract between parties for selling power at predetermined prices. The PPAs were subsequently withdrawn and currently only a few PPA contracts remain. There is now a reliability charge that can be seen as a call option: producers holding the option receive a risk premium in exchange for their commitment to deliver on their firm energy obligation (the commitment made by generators to produce energy even in time of difficult supply conditions) during scarcity periods (i.e. when the spot price exceeds the scarcity price) at a fixed price (scarcity price).

Likewise, producers can participate in the bilateral contract market in order to reduce their spot price risk exposure by signing, for example, long term forward contracts with retailers or with other producers.

Regarding regulated business, owners of the new transmission lines assume the risks of the recovery of assets and the operation and maintenance costs. Distribution companies face demand risks. Traders must secure their obligations by means of guarantees. However, recent events have shown that pure retailers exposed to spot prices can partially transfer their market and credit risks to the market. Large consumers face their own risks according to the contract terms they have agreed with the power producers.

3.3. TRANSITION AND POTENTIAL MARKETS

3.3.1. China

Structure and ownership: Prior to the reform, the power sector was publicly owned, vertically integrated and operated through state-owned enterprises. Moreover, consistent with the conditions of central planning, ownership and control were concentrated almost exclusively at the national level. The central government planned the scale and location of all power projects, provided the investment funds for infrastructure expansion, operated the system and set priorities according to which end users received electricity services.

In the first stage of the reform, the central government partially decentralized the investment authority in the generation subsector. Local governments, state owned industrial enterprises and even domestic private (and some foreign) investors were invited to build new power plants. These reforms have been mainly implemented as a response to the chronic power shortages in the 1980s that were perceived by the government as a serious bottleneck for economic development [44].

The reform was deepened after 2002. Five large power generation groups were established: the China Huaneng Group, the China Datang Corporation, the China Guodian Corporation, the China Huadian Corporation and the China Power Investment Corporation. They accounted for about 40% of the total installed capacity. Two power grid operators were also founded: the State Power Grid and the China South Power Grid. They were made responsible for electricity transmission, distribution and retailing.

The Chinese electricity industry has a diverse ownership structure, but most of the installed capacity is owned by state holding enterprises. In 2010, power companies owned by the central government controlled about 60% of the total installed capacity. Private involvement in the power sector is relatively small and mostly in the form of joint ventures [44].

Regulatory arrangements: In the initial period, the SERC was the independent regulatory agency overseeing the power sector but it had only a limited role. The most important regulatory functions such as project approval and electricity pricing remain with the NDRC that is also responsible for energy policy formulation. In 2008, the National Energy Administration was established as part of the NDRC. It was made responsible for drafting the energy development strategy, plan and policy, and for making suggestions about relevant market mechanisms [45]. As part of the efforts to streamline government agencies, the government shut down the SERC in March 2013 and transferred the agency's regulatory duties to the National Energy Administration.

Network regulation: The network is almost wholly controlled by two companies: the State Power Grid and the China South Power Grid. Power generating companies are obliged to supply electricity to them under PPAs. The PPAs take the form of fixed and long term contracts. In order to access the network, power producers are required to have a licence awarded by the SERC.

Retail energy prices: Electricity prices are regulated by the state pricing authority of the NDRC. Nonetheless, some important issues associated with electricity prices are decided by the State Council. The electricity prices are decided according to the principles of unified leadership and classified regulation. According to the laws and regulations, a hearing is held if the electricity price for households need to be adjusted.

In 2005, the NDRC issued the Interim Measures on Grid Price Regulation, the Interim Measures on Transmission and Distribution Price Regulation and the Interim Measures on Sales Price Regulation that clarify the main measures of the electricity price reforms. In the same year, the Law on Renewable Energy stipulated the price regulation principle for renewable energy. The price mechanism is in transition from a government decided to a market determined scheme.

Special incentives: As a response to growing energy shortages, the NDRC issued the Medium and Long Term Energy Conservation Plan in 2004. As part of this plan, detailed regulations were issued to encourage the uptake of generation technologies with large capacities, high efficiency, low water consumption and effective environmental control. These regulations have encouraged the construction of supercritical and ultra-supercritical coal fired power plants with higher thermal efficiency and lower emissions. At the same time, small, old and inefficient power plants have been closed [45].

Moreover, as a response to the growing awareness of China's contribution to global GHG emissions, the government enacted the Renewable Energy Law in 2005. This law created a coherent framework for promoting investments in renewable energy. It obligated grid companies to connect all renewable plants and to purchase all electricity generated by them. This law, assisted by other measures to support renewables such as Clean Development Mechanisms (CDMs) under the Kyoto Protocol, resulted in a rapid expansion of the installed renewable energy capacity. For example, installed wind capacity increased from 1 GW in 2005 to 62 GW in 2011 [45].

Market mechanisms: The Chinese electricity market is organized as a single buyer model: the State Power Grid and the China South Power Grid purchase all electricity and supply it to the end users. This includes power produced by the five large state-owned generation companies and IPPs.

Risk allocation: High coal prices (due to coal shortages) and dry weather conditions pose risks and lead to a surge in electricity prices and further electricity shortages. Given the transitory nature of the regulation and pricing, the ultimate allocation of investment risks is somewhat opaque.

3.3.2. India

Structure and ownership: Prior to the reform, the SEBs were responsible for generation, transmission and distribution of electricity. The SEBs were state-owned entities, operating under a universal service obligation regulation. In the first phase of the reform, IPPs were introduced in the electricity industry. In the second phase, several Indian states (such as Orissa) took initiatives to restructure and privatize their SEBs [16]. In the third phase, the national government consolidated the state reform initiatives of the 1990s in the Electricity Act of 2003. This act mandated restructuring and corporatizing of electric utilities and establishing an independent regulator as steps that would increase the accountability of the utilities and limit state government control. This act resulted in a fundamental change in the sector's structure and ownership. By 2013, all states in India had established independent regulators, the SERCs. Restructuring of the SEBs has been implemented in 19 states. The remaining ten states have a single utility operating as a corporation, a power department or a SEB [46].

The generation capacity grew threefold after the reform. In 2014, the total power generating capacity was 214 GW, making India the fifth largest power system in the world. The private sector has emerged as a major driver of growth in generation capacity. Private investors controlled 62.5 GW (29%) of the total generating capacity in 2012. The remaining capacity was owned by the federal and state governments [46].

The interstate transmission network is owned by the Power Grid Corporation of India Ltd, an enterprise of the central government, and by various state government companies. Power Links Transmission Ltd., a joint venture between Power Grid Corporation of India Ltd. and Tata Power Company, owns the 400 kV, 1166 km long Double Circuit transmission line. In Western India, Reliance Infrastructure, a private company, owns some transmission lines.

Regulatory arrangements: The Ministry of Power deals with perspective planning, policy formulation and processing projects. The Central Electricity Authority advises the Ministry of Power on all technical and technoeconomic matters associated with the electricity sector. The Central Electricity Regulatory Commission (CERC) was established under the Electricity Act of 2003. It is responsible for regulating electricity prices for generation companies owned by the central government and for those that supply electricity to more than one state. It also regulates the interstate transmission of electricity. The CERC issues licences for interstate transmission and trading and promotes the development of electricity market. It also specifies the grid code that stipulates grid standards. All states have constituted SERCs for carrying out functions similar to those of the CERC in their own jurisdictions. The Power System Operation Corporation Limited is responsible to ensure the integrated operation of the national grid in a reliable, efficient and secure manner. It operates the National Load Despatch Centre and five Regional Load Despatch Centres. The State Load Despatch Centres are apex bodies to ensure integrated operation of the power system in a state.

Network regulation: SERC is required to ensure non-discriminatory open access to both the transmission and distribution systems with the aim of promoting competition [46].

Retail energy prices: Prior to the reform, distribution companies and the SEBs worked together to determine retail electricity prices by following the financial principles specified in the extant act that permitted a reasonable return on investments. In some smaller states, local electricity departments were responsible for determining retail electricity prices. Under the Electricity Act of 2003, each SERC is responsible for determining retail tariffs in its jurisdiction. This act also mandates that the determination of retail tariffs should follow the principles of encouraging competition, efficiency and good performance. The tariff should reflect the cost of electricity supply. The commissions are also required to ensure that the business of electricity supply is conducted on the basis of commercial principles and to promote cogeneration and generation of electricity from renewable sources of energy.

Special incentives: In 2008, the Indian government announced the National Action Plan on Climate Change in an attempt to address environmental concerns. As part of this plan, distribution companies were required by the SERCs to procure certain percentage of renewable energy as part of their electricity sales (2–10%) [47]. Renewable energy generation capacity increased sharply in response to these government incentives. In 2013, grid renewable energy capacity amounted to 25 GW or 12% of total capacity; off-grid renewable capacity was 825 MW [46].

Market mechanisms: Under the Electricity Act of 2003, a generating company may supply electricity to any licensee at a rate determined by the Regulatory Commission. State Commissions regulate the electricity purchase and the procurement process of distribution licences, including the price at which the electricity shall be procured from the generating companies, from licensees or from other sources through PPAs for distribution and supply within the state. The act requires that the appropriate commissions endeavour to promote market development including power trading [48].

A generating company is also permitted to sell power to a consumer at a mutually agreed rate where the appropriate commission has allowed open access. When power is sold to a trading company by a generator, the regulatory commissions do not need to determine the tariff. When the tariff has been determined through a transparent process of bidding in accordance with the guidelines issued by the central government, the appropriate commission is required to adopt it [48]. In the present regulatory regime, a multi buyer – multi seller mechanism is applied.

The India Energy Exchange and the Power Exchange of India are two automated on-line national level trading platforms. They have been conceived to catalyse the modernization of electricity trade. Exchanges provide a day-ahead market and offer a double-sided closed auction for delivery on the following day. Buyers and sellers submit their anonymous bids electronically during the bid call session. The market clearing price is determined by the intersection point of the demand and supply curves. This uniform selling price is offered to selected buyers and sellers. Term-ahead contracts (e.g. weekly, daily, day-ahead contingency and intraday) have also been introduced. Open access in the Inter State Transmission Regulations issued by the CERC is applied for enabling these transactions. About 10% of the total volume of power produced is sold through wholesale market mechanisms at two national level exchanges. Solar and non-solar renewable energy certificates are also traded on the exchanges. Each renewable certificate represents one MW·h of electricity generated from renewable energy sources. These certificates can be used by the obligated entities to fulfil their renewable energy purchase obligations imposed by the regulators.

Risk allocation: In the present regulatory regime, all costs are borne by the ultimate consumer. The generation tariff is determined so that if a generator is able to perform at the base norms, it has no risk to lose its fixed costs. However, if the performance is below the norms prescribed by the regulator, the generator takes the risk. If a generator does not tie up its power with long term PPAs, all risks of the fixed and fuel costs are borne by the generator. Lately, power is also procured through a competitive bidding process. In this case, if the fuel price increases, the additional fuel costs, along with any increase in the fixed costs, are also borne by the investor.

3.3.3. Indonesia

Structure and ownership: In 1950, the government of Indonesia established the National Electric Power Company (Perusahaan Listrik Negara – PLN) that monopolized the power sector by controlling all generation, transmission and distribution facilities. As part of the reform, IPPs were introduced and 25 IPP projects were contracted by 1997. The PLN is still the largest power company. It owned and operated about 85% of the country's generating capacity through its subsidiaries in 2012. It also maintains an effective monopoly over network activities. Although the most recent Electricity Law (2009) ended PLN's distribution monopoly, the regulation is not sufficient to enforce this law [49].

Regulatory arrangements: Due to the distinctive power position of the PLN, the electricity sector is also dependent on the administrative decisions of the Ministry of State-owned Enterprises, the Ministry of Finance and the National Development Board. The Ministry of State-owned Enterprises oversees the state interest in the PLN as a shareholder, while the Ministry of Finance is responsible for allocating government subsidies and loans to the electricity sector, including the PLN. The National Development Board is responsible for development planning of the energy sector and it also has some authority over economic issues, natural resources and regional development [50].

Network regulation: The rules of access arrangements are based on the Grid Code. It consists of the Grid/Distribution Management Code, the Connection Code, the Operating Code, the Scheduling and Dispatch Code, the Settlement Code, the Metering Code and the Data Requirement Code.

Retail energy prices: Retail energy prices are regulated by the government. The PLN proposes the electricity tariff that is evaluated and determined by the government. Any subsidies are born by the government. Highly subsidized electricity prices caused large financial losses for the PLN. This further reduced its ability to invest in new generating capacity. As a result, Indonesia's electrification rate (74%) is below that of many of its neighbours such as Malaysia and Thailand (close to 100%) [51].

Market mechanisms: Currently, the single buyer model is used in Indonesia. The PLN buys electricity from IPPs under long term contracts. The claim that introducing private power would drive down electricity rates because of increased competition is not valid because IPPs are protected from any competition by their long term PPAs and they pose no threat to other generators because they have no spare capacity to increase their market shares [52].

Risk allocation: The fuel price risk is borne by the PLN because IPPs buy their fuel under the supervision of the offtaker, i.e. the PNL. Any increase in fuel prices are passed on to the government. The IPPs also receive government guarantees for their projects.

3.3.4. Malaysia

Structure and ownership: Prior to the reform, the electric power industry was dominated by the National Electricity Board. Two smaller utilities provided power to the provinces of Sabah (Sabah Electricity Sdn. Bhd SESB) and Sarawak (Sarawak Electricity Supply Corp, SESCo). In 1990, the National Electricity Board was corporatized and became the TNB (Tenaga Nasional Berhad). TNB Gen was formed as a subsidiary to take over all the generation assets of TNB, the dominant electric utility. It is envisaged that eventually the split of total generation capacity between TNB and IPPs will be approximately 60% and 40%, respectively. At present, IPPs are expected to sell their energy only to the TNB, a vertically integrated utility (generation, transmission and distribution). Steps are currently underway to unbundle TNB into generation, transmission, distribution and other entities.

Regulatory arrangements: The Prime Minister's Economic Planning Unit (EPU) and the Implementation and Coordination Unit oversee all aspects of policy in the energy sector. The Energy Commission, an independent statutory body reporting to the Minister of Energy, Water and Communications, is the principal electricity sector regulator. It is responsible for implementing the sector's governing statute, the Electricity Supply Act 1990 (amended in 2001), setting tariffs and advising the government on power policies [53].

Network regulation: Legislative mechanisms necessary for the proper regulation of the industry have been developed. The Electricity Supply Act 1990 provides the legislative framework for regulation. The three important regulations under this act include the Licensee Supply Regulations 1990, the Gas Supply Regulations 1997 and the Electricity Regulations 1994. In addition, the Malaysian Grid Code was introduced as a set of comprehensive technical and operational requirements for all plants connected to the national grid to ensure safe, secure, reliable and economic electricity supply system, and access to it for all users without discrimination. The licence terms and conditions for TNB and the IPPs form part of the regulatory framework. The Malaysia Distribution Code is being finalized to supplement the above components of the regulatory framework.

Retail energy prices: Retail energy prices are determined by the Minister of Energy, Green Technology and Water on the advice of the Energy Commission. The utility company submits its proposals together with the necessary justifications that will be studied by the Energy Commission before it submits the proposal to the minister for final approval.

Special incentives: The Ministry of Energy, Green Technology and Water introduced the National Renewable Energy Policy and Action Plan in 2010. This plan defines the targets for renewable energy until 2050 when renewable energy should amount to 24% of the total energy mix, progressing from 1% in 2011 to 9% in 2020. The government passed the Renewable Energy Act 2011 and established a FIT system to encourage the uptake of renewable energy [54].

Market mechanisms: The single buyer model has been adopted in Malaysia. TNB supplies power to the end users. This includes power produced by TNB-owned generators and that purchased. In eastern Malaysia, two utilities of a much smaller size provide power to the provinces of Sabah and Sarawak. Traditionally, IPPs had to negotiate with the single buyer about the sale and purchase prices and other terms. This changed and the IPPs now have to bid to be able to build generation plants. Once they are successful and their plants are ready, their ability to dispatch will depend on their negotiated prices. The utility will dispatch available generation on a least cost basis, subject to system constraints.

Risk allocation: The government is transferring risks to the private sector through the privatization process.

3.3.5. Philippines

Structure and ownership: Prior to the reform, the Manila Electric Railroad and Light Company was the largest private electricity company and the National Power Corporation (NPC) was the largest state-owned electricity enterprise. The two companies had coexisted in the electricity sector for nearly 70 years. IPPs were introduced as part of the reform. The National Transmission Company was separated from the NPC. The wholesale electricity spot market (WESM) was introduced in 2006 [55], [56], [57].

The concession contract of the National Transmission Company was awarded to the National Grid Corporation of the Philippines to operate and manage the transmission system for a period of 25 years, renewable for another 25 years. However, the ownership of transmission assets still remains with the National Transmission Company. Almost 93% of the NPC plants have already been privatized and turned over to private corporations. The NPC Small Power Utilities Group plants (located in an island grid) will remain under government control to continue their mandate of providing missionary electrification.

No generation company is allowed to own more than 30% of the total installed generating capacity in the Luzon, Visayas and Mindanao grids and/or 25% of the total nationwide installed generating capacity. Moreover, no generation company associated with a distribution utility may supply under bilateral contracts more than 50% of the distribution utility's total demand without prejudice to the bilateral contracts entered into prior to the entry into force of the EPIRA in 2001.

Regulatory arrangements: The Energy Regulatory Commission (ERC) is responsible for overseeing the power sector. The EPIRA mandates the ERC to promote competition, encourage market development, ensure customer choice and penalize abuse of market power in the restructured electricity industry. It has some flexibility in designing the mechanisms for setting the rates and charges for transmission and distribution of electricity. It may adopt alternative forms of internationally accepted rate setting methodologies, provided that they ensure a reasonable price of electricity. The ERC approves the price determination methodology and market fees, sets the criteria for eligibility for membership in the WESM and defines the performance standards through the Grid Code. The ERC maintains a level playing field, prevents the abuse of market power in the competitive sectors (generation and supply) and regulates the transmission and distribution sectors.

Network regulation: In this new deregulated industry, all generators are required to operate in the WESM regardless of the level of bilateral contracts they may hold. Before they can operate and generate electricity, all generators must be authorized to do so by applying and securing a certificate of compliance from the ERC. A generation company may develop and own or operate dedicated point–to–point limited facilities provided that such facilities are required only for connecting to the distribution system and are used solely by the generating facility, subject to prior authorization by the ERC. The distribution utilities may likewise provide connection facilities provided that the generator pays for the facilities. Such payments are not refundable, unless otherwise provided for in the Renewable Energy Act and its Implementing Rules and Regulations. Alternatively, a distribution utility may provide the connection facilities subject to connection charges mutually acceptable to the parties if they are not part of the distribution utility’s regulatory asset base or plant in service.

Retail energy prices: Under the Republic Act 9136 of 2001, the retail price is not subject to price regulation, but all retail suppliers must apply to the ERC as a registered retail electricity supplier. Pursuant to its mandate to promote competition, the ERC approved and adopted a resolution in 2007 prescribing the timelines for full retail competition and open access. It states that open access and retail competition shall commence as soon as the following two preconditions are met: (1) the privatization of at least 70% of the total capacity of generating assets of NPC; and (2) the transfer of the management and control of at least 70% of the total energy output of power plants under contract with NPC to the IPP administrators. Furthermore, two vital requirements should also be met: (1) the adequacy and establishment of all necessary infrastructures (that includes transmission networks, generation supply, customer switching system, etc.); and (2) the promulgation by ERC of all pertinent rules and regulations governing retail competition and open access.

Special incentives: The government passed the Renewable Energy Act in 2008. This act aimed at enabling the Philippines to move rapidly towards its goal of being 60% energy self-sufficient by 2010 by developing and utilizing renewable resources such as solar, wind, hydropower, ocean and biomass. This act introduced a number of incentives to encourage the uptake of renewable energy such as a seven year income tax holiday, tax exemptions for CO_2 credits generated from renewable energy sources and lower corporate income tax [58].

Market mechanisms: The WESM trading process is a gross pool market where all energy transactions are scheduled. Trading participants include generation companies and customers registered as either a direct or indirect WESM member. They submit on-line energy offers and the market operator matches the offers of the generators with demand bids of customers by prioritizing the lowest offers (generator) and highest bids (customers). Next, the market operator submits the dispatch schedules to the system operator for central dispatch and informs the trading participants of the prices and schedules. Electricity is then dispatched to the buyer for distribution to the end users. Finally, the electricity dispatch price is measured and settled using the market clearing price and schedules.

Risk allocation: In a competitive generation sector, investment risks are borne by the investors, unless they can pass it on to others by signing a contract with an offtaker. In some of the energy conversion agreements still in force today, offtakers agree to supply the fuel. Even PPAs signed by IPPs often have fuel pass-through clauses that shift the fuel price and availability risks to the offtaker. According to the provisions of the Renewable Act of 2008, investors in renewable energy will be assured of a guaranteed payment at a fixed rate per kW·h (FIT) and eventually this reduces their risks by passing on the fixed rate to the consumers. The supplier and distribution companies buy all of their energy from the market. If they wish to hedge against market price fluctuations, they need to enter into contracts with the generators. The typical contracts are of CFD type.

3.3.6. Thailand

Structure and ownership: In 1969, the EGAT was established. It took the responsibility of providing electricity for the general population and became the largest state-owned electricity company. It controlled generation and transmission networks throughout the country and left the distribution of electricity to the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA).

Since 1992, the Thai government has promoted a greater role for the private sector in the power generation business in the form of IPPs and SPPs [17]. The role of the private sector in the electricity industry has been increasing since the initiation of the reform in the 1990s, mainly through their ownership of IPPs and SPPs. They have generally supplied electricity to EGAT on the basis of long term PPAs, typically backed by a government guarantee for a fixed return on investment, and supported by the provision of a number of tax and non-tax incentives. The entry of IPPs and SPPs altered the industry ownership from public to a mix of public and private owners. The share of private generating companies in electricity supply has continuously increased since their entry in the mid-1990s. Much of the increase is contributed by IPPs. In 2010, EGAT owned 44%, IPPs nearly 45% and SPPs 9% of the total electricity generation capacity [59].

The current structure of the Thai electricity industry is a kind of monopsony. Under this structure, EGAT – a combined national generation and transmission utility – has the responsibility for electricity generation, power purchase, system operation, electricity transmission and bulk power supply to the distribution utilities. Furthermore, EGAT is playing a dominant role in the system development, planning and decision making processes in industrial policy. EGAT buys electricity from the IPPs, SPPs and neighbouring countries on the basis of PPAs and memorandums of understanding. SPPs can sell their electricity either to EGAT or to industrial customers located next to their plants. EGAT mainly sells electricity to the distribution utilities MEA and PEA. It also sells a small portion of electricity directly to some large customers through its transmission grid. The distribution and retail segments of the electricity industry are dominated by the MEA and PEA.

Regulatory arrangements: Prior to the implementation of the electricity reform programme, the regulatory arrangements for the Thai electricity industry were rather complex, typified by a multiplicity of institutional involvement. For example, the industry was centrally operated and planned by the three state electric utilities (EGAT, MEA and PEA) under the supervision of several government agencies. There was no single agency providing an oversight of the policy direction. Hence, decisions were typically made through a consensus among various agencies.

The establishment of the National Energy Policy Council and the National Policy and Planning Office under the National Energy Policy Council Act in 1992 was aimed at alleviating this problem. The National Policy and Planning Office, later renamed Energy Policy and Planning Office (EPPO), was formed as the secretariat of the National Energy Policy Council that served as a direct link to the prime minister's office on energy issues [60]. The formation of National Energy Policy Council and the EPPO — and subsequently the Ministry of Energy (MOE) in 2002 — marked significant changes in the institutional arrangements for the industry. The MOE was set up to unify several government agencies directly related to energy policy, regulation and implementation.[5] However, there has been no independent regulatory body solely responsible for regulating the industry and balancing the interests of key stakeholders such as investors and consumers. In addition, despite the absence of an independent regulatory body, the government still planned to corporatize the state electric utilities in 2005. The lack of an independent regulatory body could be a key factor contributing to the unaccountability, opacity and non-creditability of regulatory decisions, making the investment climate of the industry less attractive.

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[5] The MOE comprises four main organizations. The Department of Energy Business is responsible for the regulation of safety and quality in oil and gas businesses. The Department of Mineral Fuels is mandated to explore, develop and manage petroleum and coal resources. The Department of Alternative Energy Development and Efficiency is responsible for research and development of renewable energy and energy conservation. The main task of EPPO is to define measures, rules and regulations for the domestic energy industry.

It was nearly 16 years after the initiation of the reform that the first independent regulatory body, the ERC was established (in 2008) under the Energy Industry Act of 2007. The ERC is responsible for regulating energy industry operations to ensure compliance with the objectives of the Energy Industry Act under the policy framework of the government [61]. This regulatory body is expected to help increase transparency, creditability and public participation in decision making about the energy sector. In 2009, the Office of Energy Regulatory Commission was established in order to support the ERC in regulating the energy industry.

Network regulation: Prior to the enactment of the Energy Industry Act in 2007, the responsibility for issuing licences for supplying electricity was assigned to EGAT, a combined national generation and transmission utility under the supervision of EPPO. This, argued some, hindered fair competition in power generation and discriminate other power producers because EGAT was responsible for the bid solicitation process and its subsidiary might be one of the competitors submitting a bid to obtain a licence for power generation.

Since the enactment of the 2007 act, this responsibility has been transferred to the newly created regulator, the ERC. In order to ensure a fair and transparent competition for all power producers, the ERC has introduced five classes of electricity licences, including generation, transmission, distribution, retail and system operation. As a result, all public and private firms that intend to operate in the power industry (EGAT, MEA, PEA, IPPs, SPPs and very small power producers (VSPPs)) are obliged to apply for a licence for generation, transmission, distribution or retail.

Retail energy prices: Tariff setting is based on a combination of rate of return and incentive regulation. It is dominated by rate of return approach because the government assigns high importance to the financial status of the three electric utilities: EGAT, MEA and PEA. Incentive regulation was incorporated in tariff setting through the so-called X factor (efficiency improvement) since 2000.

The current retail electricity tariff comprises two components: a fixed base tariff and an additional cost from an automatic adjustment mechanism. The base tariff reflects the investment costs of utilities in developing power plants and transmission lines as well as energy costs with certain assumptions about fuel prices, inflation rates and exchange rates [62]. The base tariff is derived from the revenue requirement of each activity to ensure each state utility's financial viability and capability to expand its power business in the future. The estimation of the revenue requirement is based on explicit assumptions, particularly on fuel prices, inflation rates or the consumer price index, efficiency improvement of each activity (X factor), investment plan, financial criteria, lump sum financial transfer and remittances to the government [63]. The adjustment mechanism includes a pass-through of specific uncontrollable costs from operators to consumers to attract private investors.

Special incentives: Efforts have been made to diversify away from the use of fossil fuels for electricity production by increasing the use of indigenous renewable energy resources in order to enhance the security of electricity supply as well as to reduce environmental impacts. It is, however, widely acknowledged that renewable energy suffers from commercial viability problems as compared with conventional energy sources. Therefore the government has initiated measures to help improve the commercial viability of renewable energy. The measures include pricing subsidy (known as adder provision) and financial incentives through investment subsidy and soft loan provisions [64]. The adder provision is a surplus on top of normal energy purchasing prices received by power producers when they sell electricity to the utilities [65]. The amount of adders varies depending on the type of renewable energy being used. The adders are provided for a period of seven years from the starting date of commercial operation.

Market mechanisms: Since the reform was initiated in 1992, the industry has operated under a single buyer structure. EGAT is responsible for about 50% of electricity generation and controls the entire transmission network. The private sector is allowed to participate only in the generation business. IPPs are obliged to supply their entire electricity output to EGAT. SPPs, however, can sell their electricity either to EGAT or to industrial customers. In order to access the network and supply electricity to EGAT, the private power producers are required to have a licence awarded through a bidding process. Private awardees then sign PPAs that are typically fixed in long term contracts. The government allows generous terms for PPAs in order to attract private investments. These terms include ‘take or pay’ contracts, provision of a number of tax and non-tax incentives such as tax breaks for up to eight years and exemption from the machinery import tax [60].

Risk allocation: A review of the existing tariff settings reveals that electricity customers are obliged to bear all risks. Under the current tariff structure, the fixed base tariff accounts for the investment costs of the three electric utilities: EGAT, MEA and PEA. The automatic adjustment formula is designed to pass through uncontrollable costs from operators to customers. An increase or decrease in the adjustment formula is based on changes in fuel costs and on power purchased from EGAT, IPPs, SPPs and VSPPs. This practice results in a full cost pass-through that allows operators to transfer all risks to the consumers.

3.3.7. Pakistan

Structure and ownership: Prior to the reform, the Water and Power Development Authority (WAPDA) supplied electricity to the entire country, except Karachi where power was supplied by the Karachi Electric Supply Company. IPPs were introduced as part of the reform. WAPDA was unbundled and its generation assets were taken over by the Pakistan Electric Power Company. The National Transmission and Dispatch Company (NTDC) was created to take over transmission from WAPDA. WAPDA’s distribution assets were divided into 10 regional distribution companies. The Pakistan Atomic Energy Commission (PAEC) is responsible for construction, operation and maintenance of NPPs in pursuance of plans and programmes of the government. Currently, it owns three NPPs.

Generation companies can issue corporate registered bonds and shares at discounted prices. Foreign banks are allowed to underwrite the shares and bonds issued by the private power companies to the extent allowed in the laws of Pakistan. Sponsors can divest equity after six years from project commissioning. The tariff comprises of the capacity purchase price and the energy purchase price with adequate provision for escalation. Some tax exemptions are offered to power companies.[6]

Regulatory arrangements: The Ministry of Water and Power deals with matters relating to the development of water and power supply. The National Electric Power Regulatory Authority (NEPRA) is an independent regulatory authority responsible for promoting a competitive and efficient power sector while safeguarding the interest of electricity consumers and power

[6] A total of nine projects with 1900 MW gross capacity has been added under the 2002 policy. As of 2014, the Private Power and Infrastructure Board processed 31 project with 8592 MW gross capacity to be commissioned in the next five years.

sector investors. It also approves tariffs for IPPs before a letter of support is issued by the Private Power and Infrastructure Board (PPIB). It may also advise the PPIB, the provincial and the Azad Jammu and Kashmir private power cells on the maximum acceptable tariff for a project before the bid. The PPIB is responsible for assisting private sponsors in coordination with various governmental agencies to carry out negotiations on the implementation agreement, issue the letter of support, and monitor and follow up on the progress of various projects. One window support at the provincial level is provided by the provincial and the Azad Jammu and Kashmir private power cells for projects located in their respective territories [66]. The Alternate Energy Development Board was established under the Ministry of Water and Power to promote and exploit renewable electricity sources.

Network regulation: Network regulation is based on the open access principle of treating all participants in the transmission and distribution system (extant and potential) fairly and equitably without any discrimination and prejudice. Generators must pay a connection charge to cover the costs of the assets required to connect them to the network and a use of system charge for remaining connected to the network. The network tariff comprises two parts: the fixed and the variable operation and maintenance charges. The tariff is reviewed at regular intervals.

Retail energy prices: The end user tariffs are determined by the NEPRA. The tariffs have two parts: the capacity purchase price and energy purchase price. The former covers debt service, fixed operation and maintenance costs, insurance expenses and return on equity. It is designed to protect the investors' profits. The latter covers variable operation and maintenance costs and fuel costs. The end user prices determined by the NEPRA require the approval of the government. Affordability has always been a key consideration for the government.

Market mechanisms: The single buyer model is used in electricity trading. The NTDC purchases electricity from all generators and sells electricity to regional distribution companies that ultimately supply it to the consumers everywhere except the Karachi Metropolitan area. These distribution companies are working under the umbrella of the Pakistan Electric Power Company since 1998. Electricity in the Karachi Metropolitan area is supplied by the Karachi Electricity Supply Company, a privately owned enterprise.

Risk allocation: The risks involved in electricity production have been transferred to the consumers. Investors are motivated to make long term supply contracts by announcing an upfront tariff for purchasing electricity. This upfront tariff was established to provide a cover for investment, fuel cost and exchange rate risks.

3.3.8. South Africa

Structure and ownership: The South African electricity supply industry remains dominated by the state-owned and vertically integrated utility Eskom. It produces almost all of the electricity in the country, and owns and operates the transmission system as well. It also distributes electricity to large consumers. The remainder of electricity distribution is undertaken by municipality-owned companies. Private participation in the power sector is limited and mainly takes the form of renewable energy feed-in tariff (REFIT) and other renewable energy projects or by partnership with the government in nuclear projects.

As the REFIT programme has progressed and as the government continued its efforts to bring private sector into power generation, there has been an initiative to separate the independent system operator from Eskom in order to promote an equal playing field for all generators. There was also an attempt to consolidate the fragmented electricity distribution sector into six regional distributors to address the issues of differentiated pricing and insufficient regulation, and to support smaller distributors in rural regions. Currently this programme is on hold.

Regulatory arrangements: The National Electricity Regulator (NER) is responsible for licensing all electricity suppliers, approving tariffs, monitoring the quality of supply and settling disputes.

Networks regulation: The NER is responsible for publishing REFITs and also for approving any PPAs to be signed between a generator and the single buyer office. The office was within Eskom but the plan was to ring-fence and possibly take it out of Eskom in the near future. The government will guarantee the single buyer agreements.

Retail energy prices: Retail electricity prices are not regulated but are determined by individual distributors. The municipalities apply to the National Treasury for their retail price increases but they are not legally regulated.

Special incentives: Generators under REFIT regulation will receive special pricing and will be regulated through a generic PPA. The generic PPA was under development in 2014. When entering into force, it will be signed based on the REFIT specified for the particular technology with an agreed escalation rate.

Market mechanisms: Eskom operates an internal pool that generates an optimal dispatch schedule. The system operation and the procurement of auxiliary services are within the preview of Eskom [67]. The average generation price is regulated by the NER.

Risk allocation: The current regulatory environment allows Eskom to pass through prudently incurred costs and a return on assets according to the regulatory asset base. It also allows for a return on assets in construction that reduces the investment risk for Eskom. This methodology effectively allocates most of the risks to the consumer assuming that it is fully implemented but it also provides for low prices due to the limited utility rate of return allowed on assets. NER is currently smoothing the increases in electricity prices to reach levels set by policy makers over a five year period. This is why Eskom has recently received government support in the form of guarantees and equity.

The cost recovery mechanism regulation allows new generators to recover their costs through the general tariff but at individually determined prices. The generic PPA under development is expected to distribute risks more evenly between the generator and the buyer.

3.3.9. Turkey

Structure and ownership: Prior to the reform, the electricity industry was dominated by the state-owned vertically integrated utility, the Turkish Electricity Authority. As part of the reform in 1994, the authority was split into two state-owned companies: the Turkish Electricity Generation and Transmission Company (TEAS) and the Turkish Electricity Distribution Company (TEDAS). The TEAS was made responsible for generation and transmission and the TEDAS for the distribution and retail sale of electricity. Private investors were also allowed to participate in the power sector. Different models were used to encourage private participation, including build–operate–transfer (BOT), build–own–operate (BOO) and the transfer of operating rights (TOOR).

In 2001, further steps were taken towards a fundamental restructuring of the electricity sector. As part of this restructuring, TEAS was unbundled into three separate companies: the Turkish

Electricity Transmission Corp. (TEIAS), the Electricity Generation Corp. and the Turkish Electricity Trading and Contracting Corp. (TETAS).

The Electricity Generation Corp. is a state-owned company. It is responsible for operating the state-owned generation plants that were not transferred to the private sector. It also remains the asset owner of plants for which only operation rights have been transferred to the private sector. If it becomes necessary, this company shall build and operate new power plants.

The TEIAS is the TSO. It has taken over all transmission facilities in the country and became the national grid company to plan, build and operate the transmission facilities. It also assumes the function of market balancing and reconciliation.

The TETAS is responsible for the execution of long term BOT, BOO and TOOR contracts previously signed between generators, distribution companies and retailers. It also acts as a wholesale trading company to make new contracts where necessary. Its main function is to continue its work in the transition period until a fully liberalized market is established. The wholesale tariffs are set by this company. The State Generation Company sells most of its electricity to the State Trading Company.

The role of the private sector in the electricity industry has increased since the initiation of the reform, mainly through its ownership of IPPs. In 2001, IPPs had an installed capacity of 7.2 GW and produced about 30% of the total electricity. By 2010, the installed capacity of IPPs increased to 25.4 GW and they produced about 55% of the total electricity. In the period 2001 to 2010, 10 GW natural gas fired power plants, 2.8 GW coal, 1.5 GW wind and 2.5 GW hydropower capacities were commissioned by the private sector.

Regulatory arrangements: The Electricity Market Law entered into force in March 2001 with the establishment of an independent regulatory body called the Energy Market Regulatory Authority (EMRA). It is responsible for licensing, supervising, tariff setting and market monitoring.

Network regulation: The transmission and distribution system operators are obliged to provide non-discriminatory access for all system users, including eligible consumers connected and/or to be connected to the transmission system. The necessary investment for constructing new lines and other facilities may be made or financed by the licence applicant. The facilities would be owned by the TSO or the distribution system operator, and the investment would be paid back to the licence applicant in less than ten years after the start of operation.

Retail energy prices: Competition in retail supply was introduced in a phased opening process. Initially, customers with consumption above 9 GW·h/year were given the possibility of selecting their power supplier. By the end of 2011, clients with consumption above 0.1 GW·h were granted this opportunity. All consumers are expected to have the chance to choose their supplier by the end of 2015. A uniform national retail tariff was applied for all distribution companies until the end of 2012. The purpose of this tariff arrangement is to protect the consumers partially or wholly from the existing price differences that result from cost differences across the distribution regions. This price equalization arrangement is based on a cross-subsidy between distribution companies, i.e. money is being transferred from profitable to unprofitable companies. Since the beginning of 2013, the price cap is set by individual distribution companies and subjected to approval by the Energy Market Regulatory Authority.

Special incentives: The Electricity Market Law provides incentives for the development of renewable energy. A separate law was enacted in May 2005 and amended in January 2011 to promote the intake of renewable energy for power production. Incentives to promote renewable energy mainly include FITs and purchase obligations for distribution companies to buy electricity from certified renewable power producers. There are other incentives, e.g. exemption from annual licence fee payments, priority in connecting to the transmission or distribution grid, and discounted land use fees. In addition, there are incentives for nuclear power projects such as the provision of sites for the reactors and guaranteed power purchase at a specified price. This incentive mechanism is considered an important tool for potential investors to take part in nuclear power projects.

Market mechanisms: The electricity market model combines bilateral agreements covering the bulk of the electricity demand with a balancing and settlement system for short term system imbalances. Two different prices are formed by the balancing and settlement implementations: an hourly marginal price and a system imbalance price. The latter is calculated on an hourly basis and announced daily. Theoretically, this price is the market price reflecting the electricity supply–demand balance under system congestion.

The government decided to implement a two-step reform programme to improve the operation of the wholesale market. First, the transitional balancing and reconciliation mechanism will be replaced by the final balancing and reconciliation regulation. The balancing market will be divided into two parts: the day-ahead planning for use in the day-ahead trade with the primary aim of providing a stabilized system for the system operator on the previous day; and the balancing power market that serves as the real time balancing of supply and demand. With this process, imbalances will be reconciled on an hourly basis. Active demand side participation in the market will be ensured as part of the reform.

The second step of the transition entails switching from day-ahead planning to the day-ahead market, a spot market where market participants act to balance their own portfolios and provide a stabilized system for the system operator (TEIAS) on the previous day. The practice of hourly reconciliation of imbalances in the real time balancing power market will continue. Following this transition, a futures market is also planned over the medium term.

In addition to the new wholesale market system, a mechanism will be developed to ensure adequate supply capacity. If electricity investments do not meet projected capacity demand, especially peak capacity including reserve, the Council of Ministers can decide to initiate a centrally organized tender.

3.3.10. Kenya

Structure and ownership: Following the structural adjustments programme in the 1990s, the government officially liberalized power generation as part of the power sector reforms in 1996. One of the first initiatives was the unbundling of the state utility in 1997. All public generating facilities were transferred to the government-owned public company KenGen. The rest of the industry was still owned by the Kenya Power and Lighting Company Limited (KPLC). IPPs were also introduced.

The generation sector comprises KenGen and IPPs. KenGen is the main player in electricity generation. It accounts for about 75% of the country's installed capacity. It is listed at the Nairobi Stock Exchange with 70% of the stakes held by the government and 30% by private shareholders. The rest of the power is produced by IPPs. They are private investors involved in generation either on a large scale or for the development of renewable energy under the FIT policy. Current players comprise IberAfrica (108 MW thermal), Tsavo (74 MW thermal), Orpower (48 MW geothermal), Rabai (90 MW thermal), Imenti (800 kW mini hydro) and Mumias (26 MW cogeneration). Collectively, they account for about 25% of the country's installed.

KPLC is the offtaker in the power market, buying electricity from all generators on the basis of negotiated PPAs for onward transmission, distribution and supply to consumers. It is controlled by the State Corporations Act and is responsible for electricity transmission and all distribution systems in Kenya. The transmission system comprises 220 kV, 132 kV and 66 kV transmission lines. KPLC is a listed company on the Nairobi Stock Exchange with 50.5% of the stakes owned by the National Social Security Fund and the government, and 49.5% by private shareholders.

It is anticipated that in the long run the power sector will be unbundled into multiple generation companies (spin-offs from KenGen, IPPs and privatized isolated power stations). The Geothermal Development company will supply steam to KenGen and IPPs and a transmission company will provide open access to all generators. There will be multiple distribution companies (spin-offs from the KPLC based on geographical areas as well as new private distributors). Vertically integrated licensed companies will provide power to rural areas under the supervision of the Rural Electrification Authority.

There are also plans to promote regional integration and to build synergies with other countries in the region in power development. The government made a commitment to enter into mutually beneficial regional interconnections with other African countries. As a result, the regional power market is evolving into a power pool with the anticipated interconnections with Ethiopia, Tanzania and other countries in the Southern African Power Pool and also strengthening the interconnection with Uganda.

Regulatory arrangements: The electricity sector in Kenya is regulated by four major organizations, including the MOE, the ERC, the Energy Tribunal and the Rural Electrification Authority.

The MOE is in charge of making and articulating energy policies to create an enabling environment for efficient operation and growth of the sector. The ERC is responsible for regulating the energy sector (tariff setting and oversight, coordination of the development of indicative energy plans, monitoring and enforcement of sectoral regulations). The Energy Tribunal is an independent legal entity and was set up to arbitrate disputes in the sector. The REA started its operation in July 2007 with the mandate of implementing the rural electrification programme. Since its establishment, connectivity of rural customers has accelerated and increased from 133 047 in 2007 to 251 056 in 2010.

Network regulation: Up to December 2008, the KPLC was the sole transmission and distribution company. The transmission role has since been taken up by the Kenya Electricity Transmission Company, the new transmission company with the mandate to build and own new transmission infrastructure financed by the government. KPLC continues to operate the transmission and distribution infrastructure in the country and is the sole offtaker of power. The reforms have also enabled the generators to sell power directly to bulk consumers according to a wheeling tariff. The network company's revenues are regulated by the ERC with a provision for fair return on investments and full compensation for operation and maintenance costs.

Retail energy prices: The end user tariffs are regulated by the ERC and provide a fair return on investments, recovery of all operation and maintenance costs including pass-through of fuel costs and recovery of any foreign exchange losses arising from transactions in foreign currencies.

Market mechanisms: Currently, the electricity market still operates as a single buyer model with the KPLC being the sole offtaker of all the power generated. Generation companies are paid a tariff regulated by the ERC. This tariff comprises several components: a capacity charge that compensates investors for their investments, a fixed operation and maintenance charge for fixed operation expenses and a variable charge that compensates the variable costs of running the plant. The tariff is intended to provide generators with a moderate rate of return on investments according to the stated regulatory asset base. There was a plan to enable direct sale of electricity to large consumers but its implementation has been pending in anticipation of the formulation of wheeling tariffs.

Risk allocation: The current tariffs provide for cost recovery at the generation, transmission and distribution levels, all borne by the consumer. All tariffs are approved by ERC and provide for recovery of capital investment, operation and maintenance costs (both fixed and variable), foreign exchange losses and fuel costs. However, the fuel cost component is measured against specific fuel consumption rates for fuel operated plants above which the generators are not compensated for inefficiencies. This provides for a full cost pass-through to the consumers while incorporating an element of fuel utilization efficiency. A regulated return on investment is also included in the tariff. Investor risks are covered for all types of generation in Kenya.

3.4. SUMMARY

This section presents the main findings about salient elements of the electricity market reforms.

3.4.1. Industry structure

In *mature markets,* the electricity industry has been restructured to facilitate the functioning of market mechanisms. Vertically integrated power companies have been unbundled into generation, transmission, distribution and retail firms. However, a growing tendency for vertical reintegration between generators and retailers has been witnessed in many countries, e.g. Australia, New Zealand, UK and Germany. Large generators have tended to acquire retail businesses, typically during the privatization process.

Notwithstanding nearly two decades of efforts to introduce competition in the generation and retail segments, the degree of competition in generation remains on average at a medium level in most *mature markets*. This suggests that the natural structure of the generation market is oligopolistic. This is understandable if one considers the magnitude of investments required to establish electricity generation assets and the priority of governments to protect residential consumers from exposure to high electricity prices.

In *transition and potential markets,* the generation segment has been separated from the conventional vertically integrated companies. Private investors (e.g. IPPs) have also been encouraged to participate in the generation business. The remaining functions of the power sector (transmission, distribution and retail) are still largely undertaken by vertically integrated entities that normally act as the single buyer of electricity and supply electricity to the consumers.

3.4.2. Ownership

In *mature markets,* the privatization of the power sector was implemented in two ways: selling existing publicly owned electricity assets and inviting private investors to implement new power projects. The privatization process resulted in a mixed public–private ownership in the power sector, except in some countries (e.g. Chile, UK and USA) and some states of Australia where private ownership dominates the power sector.

In *transition and potential markets,* private involvement in the power sector has been increasing since the initiation of the reforms, mainly through the ownership of independent power generators. However, private participation in the sector is still limited and the sector is dominated by public ownership.

3.4.3. Regulatory arrangements

Mature markets are generally characterized by a high degree of regulatory independence. The responsibility of the regulator is largely confined to monitoring compliance, licensing and regulation of the general market (i.e. to prevent the abuse of market power) and networks (i.e. to ensure non-discriminatory access to monopoly networks), and network access pricing. Besides, in many countries, electricity prices for small consumers are still subject to some form of regulations (e.g. price caps).

In *transition and potential markets,* the governments continue to have a significant role in the regulation of the industry including licensing and the setting of electricity tariffs for generation, line businesses and end users. Electricity tariffs are determined by the 'cost of service' principle in most countries.

In *all types of markets*, special regulatory incentives are provided to support the uptake of electricity generated by renewable sources. In some countries (e.g. the UK and China), nuclear energy also receives some form of regulatory support.

3.4.4. Market mechanisms

A formal competitive market has been established in most countries with *mature markets*. The market is generally organized in the form of a pool market or a power exchange. In a pool market, generators are typically centrally dispatched by the system operator to meet demand. In a power exchange, however, the generators are self-dispatched and the system operator is only responsible for balancing the market in real time. This obviously will have implications for the choice of electricity generation technologies.

Countries with t*ransition and potential markets* have not yet established formal market mechanisms and power continues to be sold through some variation of the single buyer model with a few exceptions such as India and the Philippines where wholesale competitive markets have been established have not reached the level of development as in mature markets.

3.4.5. Risk allocation

In *mature markets,* the electricity industry reform has gradually shifted the investment risks from the consumers to the investors. A range of measures have been developed for investors to manage these risks including the establishment of formal financial markets, provision of bilateral contracts through OTC markets and vertical integration of generators and retailers.

In *transition and potential markets,* most of the investment risks are allocated to the consumers. The IPPs supply electricity under PPAs which allow them to pass through their risks to the single buyer. The single buyer will deliver electricity to end users at regulated prices that are determined according to the 'cost of service' principle. These end user prices allow the single buyer to effectively recover the costs of providing electricity services and consequently transfer the risks to the consumers.

Figure 5 presents an overview of the structure and ownership in electricity markets. The vertically integrated monopoly model excludes competition and consumer choice. The single buyer model allows for competition in generation and a single buyer purchases wholesale electricity. The wholesale competition model allows the distributors (who also retail electricity) to choose their supplier. This introduces competition in generation and wholesale supply but distributors retain monopoly over their franchised customers. The retail competition model allows for competition at all levels from wholesale to individual customers.

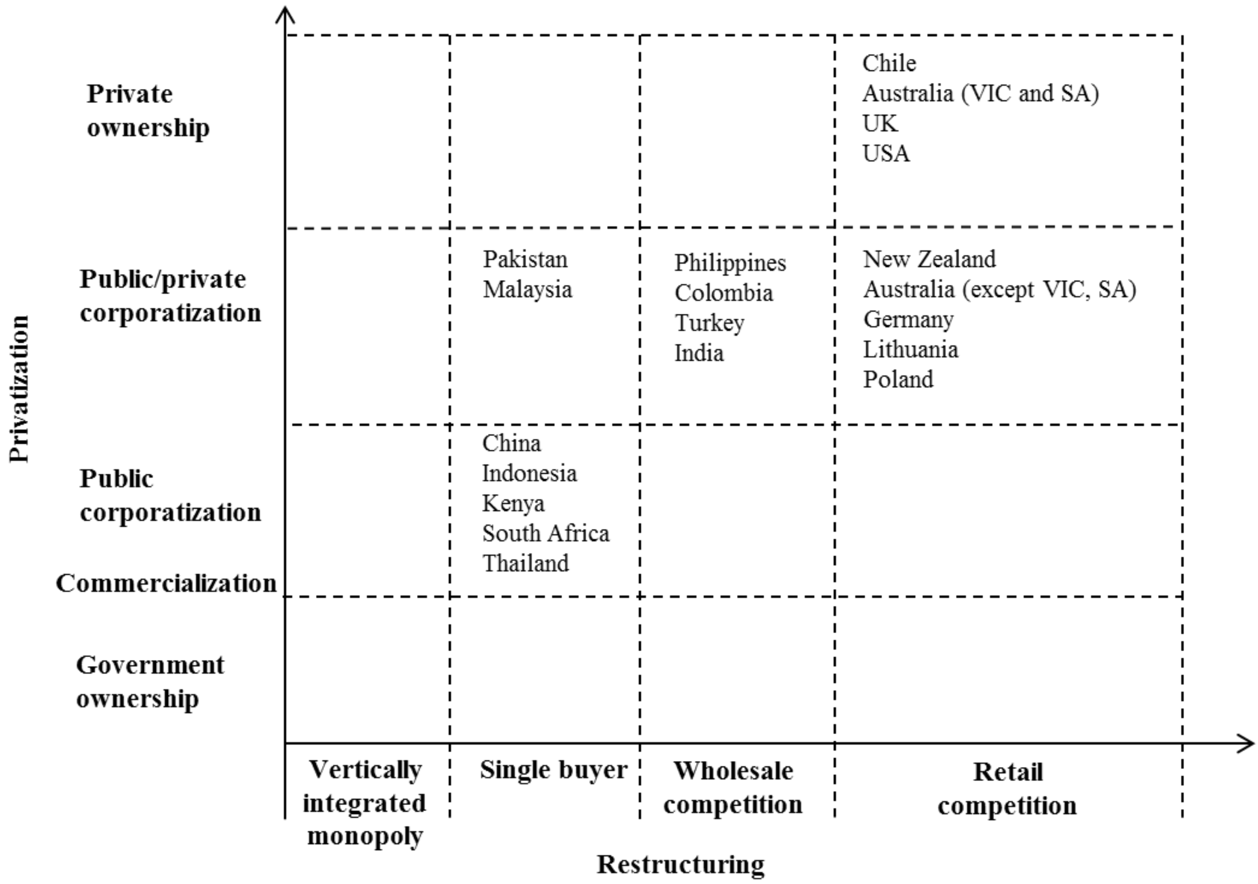

FIG. 5. Structure and ownership in electricity markets. (Note: VIC — Victoria, SA — South Australia).

Table 6 summarizes the degree of competition in the generation and retail markets in the reviewed countries. The table also shows categories of consumers who can choose their electricity providers.

Table 7 presents a succinct overview of the regulatory frameworks in various types of electricity markets. The entries show the implementation status of key elements of electricity market regulation.

TABLE 6. COMPETITION AND CONSUMER CHOICE: A SUMMARY. SOURCE: PARTICIPATING COUNTRY REPORTS

	Degree of competition		Consumer choices		
	Generation	Retail	Small[a]	Medium[b]	Large[c]
Mature markets					
Australia	High[d]	Medium[e]	√	√	√
New Zealand	Medium	Low[f]	√	√	√
UK	High	High	√	√	√
Germany	Medium	Medium	√	√	√
Lithuania	Medium	Low	√	√	√
Poland	Medium	Medium	√	√	√
USA	High	High	√	√	√
Chile	Medium	Low			√
Colombia	Medium	Low			√
Transition and potential markets					
China	Medium	Low			√
India	Medium	Low		√	√
Indonesia	Low	Low			√
Malaysia	Medium	Low			√
Philippines	Medium	Low			√
Thailand	Low	Low			
Pakistan	Low	Low			
South Africa	Low	Low			√
Turkey	Medium	Low		√	√
Kenya	Low	Low			

[a] Small: households.
[b] Medium: commercial and small-scale industries.
[c] Large: large industry.
[d] High: more than 10 generators in a jurisdiction.
[e] Medium: less than 10 generators in a jurisdiction.
[f] Low: no competition.

TABLE 7. REGULATORY FRAMEWORKS. SOURCE: PARTICIPATING COUNTRY REPORTS

Country	Independence of regulator[a]	Monitoring and compliance	Market regulation	Network regulation	Generation tariff regulation	T&D[b] tariff regulation	End user tariff regulation	Dispute resolution	Licensing
Mature markets									
Australia	High	√	√	√		√		√	
New Zealand	High	√	√			√		√	
UK	High	√	√	√		√	√	√	√
Germany	Medium	√		√		√			
Lithuania	High	√	√	√		√	√	√	√
Poland	Medium	√	√	√	√	√	√	√	√
USA	High	√	√[c]	√					
Chile	High	√[d]	√	√		√	√	√	
Colombia	Medium		√	√		√	√		
Transition and potential markets									
China	Low	√[e]	√	√	√	√	√	√	√
India	Medium	√	√	√	√	√	√	√	√
Indonesia	Low								
Malaysia	Low	√		√	√	√	√		√
Philippines	Medium	√	√	√		√	√		√
Thailand	Medium	√		√	√	√	√	√	√
Pakistan	Medium		√	√	√	√	√	√	√
South Africa	Medium				√	√	√	√	√
Turkey	Medium	√	√	√		√	√	√	√
Kenya	Medium	√	√	√		√	√	√	√

[a] High: the regulator is governed by statute and is overwhelmingly independent; Medium: the regulator is partially governed by statute and partially under government influence; Low: the regulator is largely under governmental control.

[b] Transmission and distribution

[c] The Federal Energy Regulatory Commission only regulates the wholesale market of interstate commerce.

[d] The National Energy Commission has no power to enforce compliance. The Superintendence of Electricity and Fuels is in charge of supervising compliance.

[e] The SERCs have no power to enforce compliance.

4. IMPACTS OF ELECTRICITY MARKET REFORM AND NON-REFORM FACTORS ON TECHNOLOGY UPTAKE

4.1. INTRODUCTION

This section analyses the impacts of electricity market reform and non-reform factors on technology choices made by incumbent actors and by new investors in electricity markets. This section also presents how insights gained from this analysis could be used by policy makers to design national electricity supply strategies and shape the generation technology mix.

4.2. MATURE MARKETS

4.2.1. Australia

4.2.1.1. Reform related factors

Industry structure: Over the last few years or so there has been a growing trend towards vertical reintegration between generators and retailers in the Australian electricity industry. By 2013, the three largest power companies (Origin Energy, AGL Energy and EnergyAustralia) jointly supplied over 75% of small electricity retail customers and controlled about 36% of the generation capacity in the NEM region [22].

Vertical reintegration enables these companies to internally manage the risk of price volatility in the spot market and at the same time poses a potential barrier to entry and expansion for generators and retailers that are not vertically integrated. Since 2009, around 45% of the new generation capacities commissioned or committed in the NEM regions is owned by these three large companies. In contrast, investments in generation by entities that are not integrated have been negligible in the same period [22].

Such reintegration has further reduced the scope for new market participants to become active in the energy futures markets to manage risks and secure future earnings. By 2011, low liquidity in the energy futures markets was observed, especially in South Australia where the electricity industry has the highest degree of vertical integration [68]. Such a low liquidity has created a challenging operating environment that, it is argued, is likely to deter efficient investments by new entrants.

Market mechanisms: Price signals generated in the NEM are considered to be the main drivers to deliver new investments in generation. While the investment profile in the NEM has differed across times and regions, overall nearly 13 850 MW of new generation capacity was added in the period 1999–2013. The fastest capacity growth was observed in Queensland and South Australia fuelled by high spot prices. Most of the new capacity was gas fired peaking and intermediate generation in South Australia and in coal and gas fired baseload generation in Queensland. After 2000, capacity additions gradually eased spot prices and slowed the rate of capacity expansion. Since 2005, gradually tightening supply conditions have led to higher spot prices and consequently an upswing in generation investments. Over 4700 MW of new capacity, predominantly gas fired generation, was added in New South Wales and Queensland in the three years to 2011. Some wind generation capacity was also built during the same period. More recently, subdued electricity demand and surplus capacity have delayed investments in new generation. The AEMO found in 2014 that New South Wales, Victoria and South Australia were unlikely to need new capacity for at least ten years [69]. These expectations were reflected in the limited amount of recent investments. Of the

2000 MW of capacity added over the three years to 2013-06-30, over 50% was in wind generation (partly subsidized under the MRET scheme). The balance of investments in the same period was in gas fired plants in Victoria, South Australia and Queensland. The only investment in coal fired generation was the upgrade of the Eraring power station in New South Wales [22].

Special incentives: Regulatory measures (such as MRET and CO_2 pricing) have led to a rapid development of renewable energy in power generation. At the end of 2010, total investments in large scale renewable energy power stations amounted to about Australian $9 billion. By 2010, the generating output of renewable power stations was around 12 200 GW·h in a typical year. This is equivalent to the residential electricity needs of over 1.9 million households [70]. Most of this investment went in wind generation and the installed wind capacity increased strongly: it accounted for 5.4% of the total installed capacity and contributed 3.4% of the power generation in 2012–2013 [22]. In addition, regulatory measures (especially state-based FIT schemes) also resulted in a rapid increase in solar photovoltaic generation capacity from around 1500 MW in 2011–2012 to 2300 MW in 2012–2013 [22]. Increased power generation from renewable sources has led to a reduced use of coal. Since 2012, around 2300 MW of coal plant capacity (especially older and expensively producing plants) has been shut down or was periodically off-line [22]. Overall, these changes in the generation mix contributed to the reduction of emissions intensity in the NEM from 0.916 t CO_2/MW·h of electricity produced in 2011–2012 to 0.875 t CO_2/MW·h in 2012–2013, a decline of 4.5%. This fall in emissions intensity, combined with lower NEM demand, led to a 7% fall in total emissions from electricity generation in 2012–2013 [22].

4.2.1.2. Non-reform related factors

Energy endowment: Australia is endowed with abundant, high quality and diverse renewable and non-renewable energy resources. It has nearly 10% of the world's black coal resources. A large proportion of black coal is high quality bituminous coal with low sulphur and low ash content. Most of the black coal resources are located along the eastern seaboard, especially in the states of New South Wales and Queensland where the bulk of the electricity is produced from black coal [71]. Australia also has large and widely distributed wind, solar, geothermal, hydro, ocean and bioenergy resources. Except for hydropower, where the available potential is largely developed, and wind, where the use of the resource is growing rapidly, fostered by a number of government polices to support renewable energy, Australia's other renewable energy resources are largely undeveloped [62]. This suggests that Australia has considerable potential to address the climate change challenge through the use of renewable energy.

Demand growth: There has been a long term decline in the energy intensity of the Australian economy. This trend can be attributed to two main factors. First, government policies at both the national and state levels have led to greater energy efficiency. Second, rapid economic growth has mainly occurred in less energy intensive sectors such as the commercial and services sectors relative to the more modest growth of the energy intensive manufacturing sector [71]. The declining energy intensity has slowed down the rate of generation capacity expansion but it has not evidently impacted the investors' choice of generation technologies.

Climate change: Traditionally, coal-based technology has been dominant in electricity generation. As a result, the electricity industry is one of the major contributors to the national GHG emissions. With growing concern about climate change, the transformation of the electricity industry has been put by the government at the centre of Australia's transition to a low emissions economy. A number of measures have been adopted in the past few years at both national and state levels to support the development of low carbon technologies. As a result, gas fired and wind technologies have attracted the bulk of the new investments while relatively less interest has been witnessed in coal-based technologies. The Kogan Creek power station in Queensland and the upgrade of the Eraring power station in New South Wales were the only major new investments in coal fired technology over the period 2006–2013. Several proposals for large scale solar projects were announced as part of the government's solar flagships programme. Australia's first utility scale solar photovoltaic generation plant with a capacity of 150 MW at Moree (NSW) is planned. A rapid increase in rooftop solar photovoltaic generation has also been witnessed over the past few years encouraged by state-based FIT schemes [22].

Policy uncertainty: The Labour government announced its Clean Energy Future Plan in 2011. One of the most important aspects of this plan was the introduction of a carbon price. Combined with policies such as the MRET scheme it was expected to shift the electricity generation mix and investments away from fossil fuel generation towards lower emissions and renewable technologies. However, carbon pricing was abolished in 2014 by the Coalition government as a fulfilment of their campaign commitment. A lack of bipartisan political agreement on carbon pricing is creating uncertainty that may deter investments in generation. The AEMC notes that perceptions of the longer term stability of the new CO_2 policy will be an important factor affecting investment decisions [72].

Fukushima accident: Nuclear power in Australia is a highly contentious issue. There are sharply contrasting opinions amongst the political parties and the populace at large. Overall, the public sentiment in Australia is anti-nuclear. The government's proposal in 2007 to initiate a debate on this issue and to canvass support for the introduction of nuclear power was quickly abandoned due to public and political disquiet. Currently, the government's climate change policy does not consider nuclear as an option, a testimony to the political sensitivity of this issue. The accident at the Fukushima Daiichi NPP has further deepened public concern about nuclear power.

4.2.1.3. Insights for policy makers

In 2012, the government released the Energy White Paper on Australia's Energy Transformation [71]. The paper identified three policy priorities for the energy sector: (1) the need to deliver secure, reliable and competitively priced energy for the growing population and economy; (2) the further expansion of energy exports to Asia and other growth markets; and (3) the need to improve energy efficiency across the economy, dramatically reduce CO_2 emissions and transform into a clean energy economy. Among these priorities, climate change was the most significant that is likely to influence the future of energy in the country. The Clean Energy Future Plan announced in 2011 represented the then government's commitment to reduce the country's GHG emissions. This plan, combined with other policies such as the MRET, was likely to shift the generation technology mix away from fossil fired technologies towards low GHG emissions and renewable energy technologies. Future reforms of the electricity industry such as the reform focusing on strengthening retail markets could improve the functioning of the market mechanisms through which the transition to a low CO_2 production could be facilitated in a least cost manner.

However, in 2014 the government shifted its energy policy priorities from an emphasis on GHG emissions reductions to attracting investments, lowering electricity prices and promoting gas exports. Former regulatory mechanisms to support renewable energy (such as CO_2 tax and MRET) are largely considered by the government as unnecessary regulatory barriers that would prevent energy markets from promoting its policy priorities. The carbon tax has already been repealed. The government also convened an expert panel to review the effectiveness of the MRET in promoting the uptake of renewable energy. In the review report, the expert panel argues that the MRET is distorting investment decisions in the electricity markets and it is costly for the economy. The panel has therefore recommended the government to use alternative, lower cost approaches to reducing GHG emissions. This shift in energy industry priorities creates uncertainties that may deter investments in generation technologies, especially with low GHG emissions.

4.2.2. New Zealand

4.2.2.1. Reform related factors

Industry structure: In recent years, there has been an increasing trend towards vertical reintegration between generators and retailers in the electricity industry. As a result of the Electricity Industry Reform Act of 1998, the distribution and retailing functions have been separated. Most of the distributors at that time opted to retain their line businesses and divest their retail businesses. The retail businesses were quickly acquired by the five largest generation companies in 1999–2000. By 2013, these companies controlled a significant portion of the retail market despite a dramatic decrease in their market shares in the past few years [73]. This practice provides insurance for these large generation–retailing companies to invest in new generation capacities by enabling them to manage investment risks internally. This hinders the development of a transparent and liquid futures market and consequently reduces the ability of companies engaged only in generation to secure their future revenues through long term future contracts.

Market power: The geographical diversity of generation companies is limited. For example, Meridian Energy operates almost exclusively in the South Island, while Genesis Power and Mighty River Power operate exclusively in the North Island. This reduces the scope for competition between generators where transmission constraints prevail, especially in the interisland link. Besides, the generating technology mix of these companies is not well balanced. Meridian owns most of the country’s hydropower capacities and no thermal capacity, while Genesis holds the main thermal plants. This narrows the scope for competition in dry years with reduced generation capability from hydropower plants. The lack of geographical diversity of the generation companies and their imbalanced technology mixes provide scope for them to exercise market power. This may undermine the confidence of independent investors to participate in the electricity industry.

Market mechanisms: Investments in new generation capacities have been left largely to market forces. Overall, the electricity market has delivered sufficient investments in new power stations to meet the increased demand and to replace obsolete plants [74]. Most of the new investments have been made in wind, geothermal and natural gas generating capacities.

4.2.2.2. Non-reform related factors

Energy endowment: Endowed with abundant renewable energy resources, New Zealand is one of the few countries in the world that produces most of its electricity from renewable sources, especially hydropower and geothermal energy. Since the early years, hydroelectric generation has been a part of New Zealand’s energy system and it continues to provide most of the electricity produced in the country. By the mid-1990s, hydro capacity had reached over 5000 MW and it has remained at about this level until today. The main reason is that most of the hydroelectric potential has been developed and there is limited opportunity for adding new hydropower plants.

As hydro generation gradually decreased in relative importance since the mid-1990s, the importance of gas, geothermal and wind generation has increased. The last few years have also seen increasing interest in other renewable sources such as solar and bioenergy. But the costs of natural gas have increased significantly in recent years as supplies from the major gas field (e.g. Maui) have gradually diminished. In the medium term, therefore, limited gas supplies are a potential constraint on the development of natural gas generation.

New Zealand also has extensive coal resources, particularly lignite. The country has ready access to imported coal from Australia and Indonesia. However, signals from the government indicate that it does not favour coal as the fuel for any significant expansion of the generation capacity.[7] Only about 10% of electricity was generated from coal in 2010 and the use of coal is expected to completely disappear in the medium term [75].

Climate change: The government has a strong commitment to reduce GHG emissions. Two national targets have been set: a medium term target of a 10–20% reduction (by 2020) and a long term target of a 50% reduction (by 2050) relative to the 1990 emissions levels. In order to achieve these targets, an ETS was introduced and became operational in 2008. A target of 90% of electricity generation from renewable sources by 2025 has also been set for the power sector and investments in renewable power plants will be actively supported to reach it [76].

Fukushima accident: Historically, public opinion in New Zealand has opposed nuclear power. This anti-nuclear sentiment is demonstrated by the New Zealand Nuclear Free Zone, Disarmament, and Arms Control Act 1987 that was enacted to bar nuclear powered or nuclear armed ships from entering the country. The Fukushima accident has further intensified the anti-nuclear sentiment in the country.

4.2.2.3. Insights for policy makers

The government announced its strategy for the energy sector and its role in the economy in the New Zealand Energy Strategy 2011–2021 [76]. The government's goal is to make the most of the abundant energy potential through environmentally responsible development and efficient use. The power sector is targeted to deliver 90% of the electricity from renewable sources. This target will be achieved through a set of governmental policies that provide incentives for renewable generation technologies. Further reforms of the electricity market such as the development of a transparent and liquid futures market and further restructuring of the sector to promote competition are planned to strengthen its capability to deliver a low GHG emissions technology mix at the least cost.

4.2.3. UK

4.2.3.1. Reform related factors

Regulatory arrangements: Initially, the regulator's mandate under the Electricity Act 1989 included obligations to foster a market environment that encourages and permits investments. Later, the Utilities Act 2000 extended the regulator's obligation to pursue consumers' interests by promoting competition where appropriate. It also obliged the regulator to observe the guidances issued by the government regarding social and environmental policies. The

[7] The 2007 New Zealand Energy Strategy to 2050 states that there should not be a need for any new baseload fossil fuel generation investment in the next ten years.

energy acts of 2004, 2008 and 2010 further strengthened this objective. These acts changed the duties of the regulator to comply with the government's growing interest in climate change policy. The related policy goals constrain the design and regulation of electricity markets, consequently influence the investors' choice of generating technologies.

Market mechanisms: The 1990s saw a lot of investments in gas fired capacities, particularly in combined cycle gas turbines (CCGTs) motivated by its low costs and high efficiency, but also in open cycle gas turbines built with the option to add stream turbines later. Most gas turbine investments were backed by long term contracts with suppliers. These arrangements terminated when monopolies came to an end and a power pool was established. Investors had to rely on wholesale market prices to cover their costs that proved to be feasible during the 1990s. However, prices fell significantly when competition in generation increased and after the introduction of NETA because its pricing rules did not include a markup above the costs for LOLP or any other form of capacity payment. Low prices discouraged investments during the period 2000–2005. Some new investments were made in the years 2008–2010 in anticipation of demand growth but this did not materialize in the end.

Markets have proven less successful in meeting the government's policy targets for renewable generation. It proved to be more difficult to arrange planning permission for large, visible onshore wind farms in rural areas. Proposals to impose a national plan over local opposition to investments by setting up a national infrastructure planning commission have stalled. The government has therefore turned to offshore wind farms and new nuclear projects to overcome the opposition to investment in onshore wind.

No private investment in nuclear plants took place in the UK after the reform. Sizewell B, the only nuclear plant built after 1990 (although it had been commissioned before the restructuring) was funded partly by the non-fossil fuel levy. Low energy prices caused British Energy to apply for state aid in 2004. The recovery of prices finally made it possible to be sold to EDF Energy in 2009.

Although common rules apply for all participants in the wholesale market, experience suggests that the electricity pool provided easier access for small generators than the NETA/BETTA schemes. The NETA penalizes generators for differences between the generator's actual output and contractual commitment (particularly severely for deficits). This arrangement favours both horizontal and vertical integration to the extent that they can diversify risk. Small generators, however, have found it difficult — or expensive — to manage these risks and therefore tend not to act independently of the larger players (i.e. they sell their energy to the large companies, rather than to end users). For these reasons, the market has seen vertical integration of suppliers and generators since 2001.

Network access: The National Grid Company was owned at first by the regional electricity companies. In 1995, its shares were listed on the stock exchange and disposed of their stakes. Partly due to the National Grid Company's independence, all generators are able to access the transmission network on a common and non-discriminatory basis, although the company can impose a de facto moratorium on new connections in severely congested areas.

Network pricing: The charges for connection to and use of each network are based on an estimate of long run incremental costs. The tariffs encourage investors to locate new capacities close to existing networks and close to centres of demand in the south of the country. Charges are based on the size of the connected capacity that makes the connection of renewable capacities quite expensive due to their low capacity factors. In 2010, the government announced a major review of transmission pricing, intended to assess if any alternative system would better meet government objectives[8]. Ofgem has recently proposed a new tariff scheme that would reduce network charges for renewable energy plants located far from centres of demand.

Retail pricing: Competition in retail was opened first to large customers (peak demand > 1 MW) in 1990. It was broadened to include those with peak demand greater than 100 kW in 1994 and was finally extended to all customers in 1999. To restrain the market, however, suppliers had to publish default tariffs until April 2002. Since then, competition has constrained prices, with retail prices following movements in wholesale prices and other costs of supply. This link favours investments in generation capacities whose costs vary in line with wholesale prices such as generation from fossil fuels and disincentivizes generation with high fixed costs such as NPPs.

Special incentives: The nuclear industry and some forms of renewable generation received a special stranded cost compensation paid for by consumers via the fossil fuel levy that amounted to 10% of the retail price. The levy applied for nuclear energy only until 1996 but it was sustained for renewable generation until it was replaced by the ROCs scheme. Under the latter, suppliers are required to purchase a set quota of ROCs for each unit of electricity sold to final consumers. This quota is expected to rise from 10.4% in 2010–2011 to 15.4% by 2015–2016. The ROCs scheme accelerated investments in renewables after 2000, particularly in onshore and offshore wind capacities after 2005. More recently, FITs were introduced for certain renewable generation investments and the intension is to extend this support scheme to all renewables, nuclear and (possibly) flexible generation investment projects.

The introduction of the EU ETS raised the costs of electricity generated from fuels that emit CO_2 [77]. This scheme discouraged investments in coal and oil fired generating technologies. Coal fired generation was discouraged further by the EU Large Combustion Plants Directive of 2001[9] that requires electricity companies to install flue gas desulphurization equipment for their coal fired generation plants or limit the operating hours and close them by 2016. The UK government imposed an additionally constraint by prescribing that any new coal fired capacity must be ready for conversion to CO_2 capture and storage at some time in the future.

4.2.3.2. Non-reform related factors

Energy security: Investors showed a high degree of confidence in the competitive market arrangements that applied from 1990. Government agencies responsible for issuing legal consents and licences tended to take a permissive stance, offering developers the necessary authorization when requested. Since 1990, security of supply has hardly ever been a concern, except during some short periods of very high demand because generators have diversified fuels (more gas, less coal) and fuel sources (new international gas pipelines and LNG terminals, growing imports of coal). Given the permissive attitude of the licensing authorities, markets worked well to encourage investment and to promote security of supply. Even a UK specific gas shortage in the winter of 2005–2006 was managed by allowing gas and electricity prices to increase and demand to fall in response without any need to allocate or ration gas supplies.

[8] Ofgem launched the Project Transmit in September 2010, more details and documents available from Ofgem's website at: http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

[9] EC, Directive 2001/80/EC Of the European Parliament and of the Council of 2001-10-23 on the limitation of emissions of certain pollutants into the air from large combustion plants, 2001-11-27.

Policy uncertainty: Comments by potential investors frequently indicate a degree of uncertainty over the future of non-market incentives dependent upon government policy. The large number of schemes, tariffs and obligations aimed to encourage investments in renewable energy sources has provoked confusion and questions for investors about the long run sustainability of such incentives. They are based on ambitious targets for reducing CO_2 emissions and expanding renewable energy production by 2020 but commentators note that these targets may not be achievable. The planning obstacles to investments represent an immediate constraint. The high costs of many renewable technologies will become increasingly visible in consumer electricity prices as the amount of generation from such sources grows.

Renewable energy incentives will not encourage long term investments now if high costs are expected to lead to consumer opposition and reduced payments in the future. Government policy will only be able to rely more heavily on non-market incentives, if the government can convince investors that its commitments are credible in the long run and profitable in the short run.

Fukushima accident: Developers have begun promoting new NPPs as a more dependable source of generation that can facilitate the government's CO_2 emissions reduction targets, albeit one that is unlikely to be undertaken by private investors at current market prices. Although there is some discussion of possible support mechanisms for nuclear power, The Department of Energy and Climate Change has been explicit in stating that support for nuclear may only come within the wider context of support for investments in low CO_2 technologies and not as a targeted subsidy to private investors in NPPs. This commitment to keep nuclear power as part of the capacity mix was sustained even after the Fukushima accident. A safety review by the UK's chief nuclear inspector found no fundamental weaknesses in the UK power plants and no reason to curtail the operation of nuclear facilities in the UK [78].

4.2.4. Germany

4.2.4.1. Reform related factors

Market mechanisms: Electricity markets have delivered sufficient amounts of investments in new capacities. The nuclear phase-out started with the closure of 8.4 GW(e) capacity in 2011 but existing capacity is expected to be sufficient to meet electricity demand. However, there has been a growing concern about the capability of the current electricity market arrangements to ensure future supply adequacy. This concern arises from the fact that existing gas fired power plants have gradually lost competitiveness to other generating technologies due to lower CO_2 prices and high gas prices in Europe. The average load factor of the CCGT plants is quite low and owners of these plants are struggling to make a reasonable return on their investments. In addition, expected growth in renewable energy in the medium term may further depress wholesale electricity prices and make it more difficult for generators to recover fixed capital costs. This concern has resulted in a discussion on the need to introduce capacity mechanisms and other investment incentives [32].

Network constraints: Network constraints have increasingly become an obstacle to the uptake of renewable energy. Despite continued investments in networks, not all generators are able to get their power into the system. Feed-in management measures are usually required to adjust the output levels from renewable energy sources in return for compensation. The Federal Network Agency estimates that approximately 129 GW·h of output was wasted this way and compensation payments of €10 million were required almost entirely to be paid to wind power generators [32].

There are several major network constraints in Germany. Connecting offshore wind power facilities to the network in time proves particularly difficult. In 2012, TenneT — the TSO responsible for offshore grid installations in the North Sea — announced connection delays for several projects due to lack of financing, labour resources and supply bottlenecks for high voltage direct current hardware and sea cables. It proposed measures (e.g. the creation of a direct current grid operator that could facilitate planning and assist in mobilizing the large amount of capital required [32].

There is a lack of interconnections between wind installation centres in the north (Lower Saxony) and east (Saxony-Anhalt) and the load centres in the west and south. The phase-out of nuclear power will further exacerbate this problem as nuclear capacities are largely located in the south. However, the ascendancy of solar power, largely situated in the south, and good interconnections with pumped hydro storage in Austria partially alleviate the lack of interconnections, although the potential to increase this form of energy storage is very limited because potential sites for large hydro plants have already been developed and the remaining potential is limited due to environmental regulations [32].

Special incentives: The FIT structure has made renewable energy sources attractive compared with conventional energy investments because generators face no market problems as their electricity sales are guaranteed even during a contraction of demand. FIT levels new investments in hydropower, bioenergy and onshore wind are broadly in line with the costs of new coal and gas projects. Offshore wind remains relatively less competitive [32].

4.2.4.2. Non-reform related factors

Fukushima accident: In 2001, the Social Democrat/Green government changed the Atomic Energy Law to phase out nuclear energy by 2022. As announced in their election programme, the Conservative/Liberal government changed that law again in 2010 to extend the lifetime of nuclear reactors as a bridge to a renewable energy future. The last reactors were supposed to produce electricity until about 2036. In return, the government introduced a nuclear fuel tax — €145 per gram of plutonium or uranium — and established a special fund for renewable energy to be financed by contributions from the utilities operating NPPs.

The accident at the Fukushima Daiichi NPP in March 2011 further broadened and solidified the anti-nuclear attitude both in the public and politics. The accident did not change the objective safety status of the German reactors but it changed the perception of nuclear safety. Therefore, the Conservative/Liberal government decided to decommission the seven oldest reactors, made the closure of the Krümmel plant permanent and announced that by 2022 nuclear power would be phased out. The policy became law with the thirteenth change of the Atomic Energy Law in August 2011.

The opinion polls suggest a high level of public support for renewable energy technologies, low public acceptance for fossil fired power plants due to concerns about climate change and low level of acceptance for nuclear energy [79]. For many years, surveys have indicated that German citizens are exceedingly sceptical about nuclear energy compared to those in other countries. Even the CO_2 reduction policy has not modified this attitude substantially. After the Fukushima accident, the support for nuclear power in Germany dropped further to about 20%, one of the lowest figures worldwide [80]. The 2011 nuclear policy shift reflects this broad and rather stable anti-nuclear public attitude. As a consequence, a political consensus has emerged about the nuclear energy phase-out programme.

4.2.5. Lithuania

4.2.5.1. Reform related factors

Regulatory arrangements: As part of the reform, an independent regulatory body (the NCCPE) was created and made responsible for the regulation of electricity prices, licensing, promotion and supervision of competition, customer protection, monitoring of supply service quality and dispute resolution. The NCCPE's regulatory procedures such as licensing and monitoring have direct impact on investments in generation technologies.

Licences are issued by the NCCPE on the basis of an energy company's technological, financial and management capacity assessment. This assessment was introduced in 2009 and it includes nine financial indicators in terms of revenue protection, financial leverage and commercial activity. These indicators represent a company's financial capacity. If the company's total financial capacity indicator in the last two years exceeds the bottom threshold for the normative indicator of the sector set by the NCCPE, its financial capacity is rated sufficient for performing licensed activities. Otherwise, its licence will be withdrawn. This regulatory procedure has impacts on investments and the choice of electricity generation technologies as only financially strong companies will be able to meet the requirements.

Market mechanisms: Traditionally, the NCCPE informed investors about possible future capacity shortfalls. With the establishment of the electricity market in 2010, electricity prices generated by the Power Exchange provide signals for future capacity development. Since 2010, electricity prices have declined steadily. Lower electricity prices tend to discourage potential investors. However, it is perceived that the demand for electricity will increase in the near term. Increasing demand will drive up electricity prices that will attract investors to initiate new power projects, including NPPs. In addition, the interconnection to the European electricity market also provides incentives for investors to explore potential business opportunities for supplying electricity to the wider European market.

Network access: The regulation of network access has impacts on investments in electricity generation technologies. The Electricity Law requires network operators to give priority to electricity produced from renewable energy sources.[10] Power plants using renewable and waste energy resources also get a 40% discount on the interconnection fee.

Network pricing: The network pricing practices directly impact investments in electricity generation. For larger cogeneration systems, the NCCPE defines quotas and prices for electricity to be purchased from combined heat and power (CHP) by suppliers. Currently, the quotas assure the purchase of electricity produced in 1500 hours of CHP system operation per year. New investments in large scale biomass fired CHP systems and efficient cogeneration units are also stimulated by the secondary act to the Law on Heat that sets a merit order of heat to be purchased by district heating systems and favours these technologies.

Special incentives: Special incentives are provided to attract investments in renewable energy. These include a 40% discount for power plants using renewable energy sources to connect to the network; obligation for electricity supply licence holders (generators and suppliers) to

[10] Under the Provisions of Resolution No. 1474 intended to implement the Law on Electricity.

purchase renewable electricity and sell it to their customers; obligation for the transmission network operator to ensure transportation priority for renewable electricity even when the network throughput is limited; financial support for investments that promote the use of renewable energy sources (e.g. the Lithuanian Environmental Investment Fund, EU Structural Funds); and FITs for wind, biomass and hydropower plants with less than 10 MW of capacity.

4.2.5.2. Non-reform related factors

Energy security: The current generating technology mix of the Lithuanian power system includes thermal, hydro and renewable energy technologies. The closure of the NPP made Lithuania very vulnerable to any interruptions of fuel supplies from the Russian Federation. All of the natural gas and oil consumed in Lithuania are exclusively imported from the Russian Federation. The country is heavily reliant on oil and natural gas for power production. No noticeable investments in power generation capacity were made until 2000. After 2002, private investors (generators) have begun to show interest in building renewable power plants. In order to meet the country's growing electricity demand, a combined cycle gas fired plant (450 MW) was built by the government. The Lithuanian Parliament also approved the Law on the Nuclear Power Plan in 2007. Under this plan, the three Baltic States (Lithuania, Latvia, Estonia) and Poland agreed to build a new NPP of 3200 MW(e) capacity at Visaginas. In 2012, a concession agreement with GE Hitachi was signed and was approved by the Lithuanian government. In March 2014, the government identified the country's energy dependence on the Russian Federation as one of the greatest challenges to its national security and reaffirmed its desire to progress the Visaginas nuclear project [81].

Climate change: The government has shown a growing interest in developing climate change policies. A number of policy measures have been adopted to promote the use of renewable sources in power generation. These measures have had a positive impact on investments in renewable capacities. By 2010, the share of electricity produced from renewable energy accounted for nearly 7% of the total amount.[11] By 2020, this share is expected to increase to 23%.

Fukushima accident: There has been no apparent impact of the Fukushima accident on the Lithuanian nuclear programme. In May 2011, the proposals by potential strategic investors (Westinghouse and GE Hitachi) were received. In July, the government selected GE Hitachi. This company will be responsible for the engineering, procurement and construction works for a single 1350 MW(e) advanced boiling water reactor, several of which are already operating or under construction in Japan and Taiwan China. This power plant was expected to be operational by 2020. In October 2011, the government formally notified the European Commission about its plans for the new NPP at Visaginas to be built in collaboration with Estonia, Latvia and Poland.

Favourable conditions were created by the government to attract investments in the new NPP. Public opinion also had a significant impact on the choice of this generating technology. Up to 2012, public opinion about nuclear energy was positive. The Fukushima accident had only a mildly negative impact on public opinion. The decision to build the new NPP was highly supported by the previous Conservative party in Lithuania. However, after the change to the new government formed by the Social Democratic party and the November 2012 referendum,

[11] Under the directive 2001/77/EC of European Parliament and Council of 2001-09-27 on the Promotion of the Electricity Produced from Renewable Energy Sources.

support for the new nuclear project has weakened and the future of the nuclear new build in Lithuania is less certain.

4.2.5.3. Insights for policy makers

Since 2001, liberalization of the electricity market has been underway in response to the EU requirements. However, this had a negligible impact on electricity market investments until 2010 because no real competition was started. No new generation capacity was built after 1990, except for small industrial CHP projects and renewable power projects supported by government measures such as FITs, financial mechanisms and the GHG ETS. The government has a very strong commitment to promote renewable energy.

With the liberalization of the electricity market and the establishment of the Power Exchange in 2010, real competition was introduced in the electricity sector. Electricity prices in the Power Exchange decreased steadily but international energy resource prices are increasing. Therefore, it is anticipated that market prices for electricity will increase to levels potentially sufficient to attract investors for the new NPP. The ability to access the broad European electricity market and the liberalized wholesale market connected to Nord Pool are key commercial drivers for the new NPP. After 2016, existing and planned investments in power plants will not be able to meet the increasing electricity demand in the Baltic region. Additional renewable capacities will not be able to provide the baseload power supply required in the region. The investment in nuclear power would allow Lithuania and the region to secure the required energy supply and to meet the commitments to reduce CO_2 emissions. However, after the change in the political regime and the referendum about the new NPP, the support for the nuclear new build has receded.

4.2.6. Poland

4.2.6.1. Reform related factors

Industry structure: There has been no impact of the market structure on potential investors' decisions. The structure of the electricity market has been modified in accordance with the development of the EU law. The most important items are the legal documents covered by the third energy package. The separation of supply and grid related activities was already completed, therefore nothing significant was necessary to improve the structure of the power industry, as recommended by the package. However, Poland did not pursue ownership unbundling of the distribution assets. This would weaken the economic terms for attracting new investments in the sector. In the transmission segment, the exclusive ownership of the TSO by the State Treasury fulfills the requirements of the package. The strong cooperation between TSOs does not influence the structure of the market but improves the security of electricity supply and decreases the risks for entities operating in the wholesale market.

Ownership: Private investors are not satisfied with the supremacy of the State Treasury in the ownership mix of power companies, notwithstanding the legal measures that prevent the discrimination of private investors. The privatization of power companies is progressing at a slow rate.

Regulatory arrangements: The energy regulator has several duties, including granting and withdrawal of licences; exemptions from the obligation to present tariffs for approval; and exemptions from the obligation to render transmission or distribution services. The wide scope of the regulator's powers needs to be focused and decision making made transparent. As yet, there are no complaints about the performance of the regulator and investors are satisfied in this respect.

Market mechanisms: The wholesale electricity market is quite competitive. However, the distribution of generation capacities is rather uneven. Most of the generation capacity is located in the south while the north lacks adequate capacity. This reduces the scope for competition between generators when there are transmission constraints. Attempts were made to improve this situation by initiatives to introduce a nodal transmission pricing mechanism. But this attempt failed because of the concern that it would weaken the scope for effective management of the wholesale market by the TSO.

Network access: The electricity market in Poland is based on regulated third party access ensuring that all suppliers and consumers have legally guaranteed access to the grid. Producers of electricity from renewables and cogeneration technologies have priority in dispatching. This practice reduces their investment risks.

Electricity pricing: Over the past few years, electricity prices have increased steadily. Higher electricity prices are partly attributed to the regulatory obligation of supporting renewable energy. Electricity prices for household consumers have increased even faster than for other consumer groups because the cross-subsidization of households by industrial consumers was eliminated. The structure of electricity prices for final consumers did not have visible impacts on investments in the power sector.

4.2.6.2. Non-reform related factors

Climate change: The EU environmental policy, especially the radical requirements to abate GHG emissions without promoting nuclear power as a CO_2 free source, has proven to be very challenging for potential investors in the Polish electricity sector. Despite this provision, the government plans to move forward with its nuclear programme, with the expected commissioning of planned nuclear plants around 2022. The Fukushima accident had little impact on the country's nuclear programme.

4.2.6.3. Insights for policy makers

Practically all energy policies in Poland are constrained by the EU energy and environmental policies. The fuel mix for electricity generation in Poland is dominated by coal and lignite. It is very difficult for Poland to move away from fossil fuels as required by the EU. For example, the EU requires the country to have at least a 15% share of renewable energy in the final energy consumption. This means that 20% of the electricity should be produced from renewables. Moreover, the increasing contribution of renewables will require much higher public support because it is likely to raise electricity prices.

The most severe challenge for the Polish power industry will be to meet the EU targets for CO_2 emissions reductions. It will not be possible to achieve them without going nuclear because developing and maintaining the coal-based capacity would cause enormous costs either for purchasing CO_2 emissions allowances or for installing carbon dioxide capture and storage (CCS) equipment. Policy makers will therefore need to take these costs into consideration when setting the targets for GHG emissions reductions.

4.2.7. USA

4.2.7.1. Reform related factors

Regulatory arrangements: In 1989, the US Nuclear Regulatory Commission introduced a new licensing procedure, the combined construction and operating licences. Under this new procedure, owners of NPPs are assured of commercial operation by demonstrating that their plants meet all initially agreed upon criteria for operation at the completion of the construction. There is no discernible influence of electricity market reforms on applications for combined licences.

Network constraints: Most of the large potential renewable energy sources are located in isolated and remote regions of the country. Some of the highest solar energy potential is in the sparsely populated south-western desert states of Arizona, New Mexico, Nevada and Utah. However, the highest demand for electricity is in the densely populated urban areas of the north-east. The lack of interconnection between the renewable resource centres and the load centres, it is argued, creates potential barriers for the uptake of renewable generating technologies [82].

Special incentives: A Department of Energy loan guarantee programme for the nuclear industry was authorized by the Energy Policy Act of 2005. This programme covers up to 80% of the total construction costs. There is no federal mandate that requires a minimum share of electricity to be generated from renewables. However, varying levels of mandated shares are prescribed by individual states. As of 2011, 28 states have enacted binding renewable portfolio standards that require power utilities to generate a minimum percentage of electricity from renewable resources (e.g. the solar and wind mandates in California). With the support of the renewable portfolio standards, investments in renewable energy have significantly increased (by 61% over the period 2005–2010) to $34 billion by the end of 2010. Wind energy attracted $15 billion, solar power received $9 billion and $6 billion was directed towards bioenergy, while other renewables (including geothermal and hydropower) accounted for $4 billion [82].

4.2.7.2. Non-reform related factors

Social attitudes against renewables: In the USA, wind farms are facing increasing resistance from local communities concerned about the aesthetic degradation caused by giant wind turbines that dominate the landscape and the noise pollution associated with the constant whirring of turbine blades that is audible up to 1.6 km away from the generation site. In addition, bat and bird fatalities are also an issue of growing social concern when locating wind turbines. Exploitation of geothermal resources can also lead to the degradation of pristine wild life habitats (e.g. Yellow Stone National Park in Wyoming) along with environmental pollution caused by the discharge of spent geothermal fluids [82].

Fukushima accident: After the accident at the Fukushima Daiichi NPP in March 2011, work on the South Texas Project Units 3 and 4 slowed to a halt. The investor, NRG Energy stopped all spending on the project and is likely to write off its investment in the face of deeply diminished prospects for the project after the accident.

4.2.8. Chile

4.2.8.1. Reform related factors

Ownership: The changes in the ownership of electricity assets have had little impact on investors' choice of generating technology. However, the reforms provided some project inventors with more experience in developing certain generating technologies.

Special incentives: Legal procedures were established to include renewables in the energy supply mix in 2008. The quota of renewables was initially set at 5% in 2010 and was expected to increase from 2014 on by 0.5%/year until it reaches 10% in 2024.

4.2.8.2. Non-reform related factors

Climate change and energy security: Concerns about climate change and energy security are dominant considerations for the government's energy policy. In 2008, the government enacted Law 20.257 that requires power suppliers to obtain 10% of the electricity from renewable sources in the medium term. The uptake of renewable energy is viewed by the government as a means to reduce CO_2 emissions and to diversify sources for power production.

Energy endowment: The country's generation mix is influenced by its energy endowments. Chile has abundant hydro and renewable resources, and a limited amount of yet unexploited coal reserves. Currently, most electricity in Chile is generated from hydropower and the share of non-conventional renewable electricity depends directly on measures adopted by the government to promote such sources. A significant amount of fossil fuels is imported for thermal generation. Decreasing trends in the import of natural gas since 2007 has contributed to the increased use of diesel and liquefied natural gas.

4.2.9. Colombia

4.2.9.1. Reform related factors

Market mechanisms: Under the current market mechanisms, generators submit their bids for supplying electricity one day before actual dispatch. Due to network constraints, imbalances appear, therefore penalties and benefits for imbalances are quite important matters. In order to effectively manage dispatch risks and to make more profitable bid strategies, generators have been driven towards assembling a diversified technology portfolio and integrating with retail businesses to ensure sufficient income and to mitigate credit risks. Large vertically integrated companies (active in both generation and retailing activities) have consequently emerged. Clearly, the current market mechanisms favour large power companies.

Special incentives: Electricity prices in the spot market are highly volatile, partly because of the uncertainties about water inflows into the system dominated by hydropower. Three major modifications to the wholesale market were introduced to reduce price volatility and thus encourage more investments. These measures had some impacts on the investors' choice of generating technologies. In 1997, a capacity charge based on administration mechanism was introduced to stabilize the income of power producers and consequently incentivize more private investments. Later, the firm energy obligations[12] provision was introduced with the

[12] Firm energy obligation refers to the commitment made by generators to produce energy even in times of harsh supply conditions.

aim of ensuring supply adequacy in times when hydro capacities are insufficient. The obligations are allocated through a descendent bid auction. In 2009, thermal generators were required by the regulator to submit separate bids for startup and shutdown costs to the day-ahead market.

4.2.9.2. Non- reform related factors

Energy security: The generation mix is dominated by hydropower. This makes the system highly vulnerable to weather conditions. The country's water inflow has been impacted by three major El Niño Southern Oscillation (ENSO)[13] events over the last two decades in 1992–1993, 1997–1998 and 2009–2010. Consequently, investors have realized the negative and positive impacts of this vulnerability on their profits. In order to achieve the best possible outcomes, generation agents have assembled portfolios of different technologies to manage risks and to design profitable bid strategies. The portfolios are diversified mainly through the inclusion of thermal plants due to the availability of coal and natural gas resources in the country.

Energy endowment: Since the reform started, the capacity expansion programme was driven by a neutral regulatory policy regarding technological preferences. However, the abundance of indigenous hydroelectric resources resulted in the dominance of hydropower in the capacity mix. Moreover, the last ENSO event put into spotlight the insufficiency of the natural gas transport network to effectively meet electricity demand under these circumstances. Recognizing the importance of natural gas for reliable power supply and the expected enhanced role of gas in international energy markets,[14] it is expected that the government and the Regulatory Commission for Gas and Energy will establish policies and regulatory frameworks to encourage investments in natural gas infrastructure.

Climate change: The physical interconnections with other countries and the associated effort to ensure the regulatory market integration across the country tend to influence technological choices. As Colombia is viewed as a net power exporter, investors will have the incentive to build generation facilities not only to meet local but also regional demand primarily from clean resources in view of the global emphasis on low carbon development. The government has established targets for energy efficiency and the penetration of renewable resources. Under the rational use of energy programme, efficiency gains are expected to reduce electricity consumption by 14.75% and the consumption of other fuels by 2.1% by 2015. Renewable generation capacity is expected to increase by 3.5% by 2015 and 6.5% by 2020 in the national interconnected system and by 20% by 2015 and 30% by 2030 in the non-interconnected areas.

4.2.9.3. Insights for policy makers

Given the diversity of the generation mix, the government and the regulator still have a role in ensuring that reliability and security requirements are met. As noted earlier, the system is highly vulnerable to weather conditions, so improved coordination between the natural gas

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[13] The El Niño Southern Oscillation is a global coupled ocean–atmosphere phenomenon of interannual time scale. In Colombia, it is perceived as an abnormally dry season induced by positive anomalies in the sea surface temperature over the eastern Pacific Ocean. The opposite event is La Niña that considerably increases the water inflow in the national territory.

[14] This will imply further technological developments at competitive prices.

and the electricity sectors has become an essential factor in determining the investors' decisions about generation technologies. Distributed generation and demand side responses must also be considered. In some rural areas, electricity services can be more efficiently provided by combining local sources with grid expansion. Prepaid meters have resulted in reductions in non-technical losses, lower administrative costs and have been generally accepted by consumers.

Physical interconnections with other countries and regulatory market integration (settlement of international electricity transactions) are also likely to affect decisions about the types of technology to be developed. Colombia is considered to be a net power exporter so investors are encouraged to build generation facilities not only to supply local but also international demand by using mostly clean sources and foster development with low CO_2 emissions. The penetration of renewable power sources need to be carefully studied with a view to the technological neutrality of the market. Finally, there are some concerns about the level of electricity prices and, in general, about energy prices. The manufacturing industries expect lower prices due to the availability of indigenous resources and the efficiency gains resulting from the competitive market scheme.

4.3. TRANSITION AND POTENTIAL MARKETS

4.3.1. China

4.3.1.1. Reform related factors

Structure and ownership: The post-2002 electricity reform led to the diversification of investments in the generation sector. As part of this reform, incentives have been provided for low carbon technologies, especially renewables and nuclear. Generation companies have been driven towards assembling a portfolio of different generating technologies in order to hedge against risks and to mitigate costs.

Pricing mechanisms: Prior to 2007, electricity prices for most on-grid power plants were fixed and determined on a case by case basis. A cost-based method was used to determine electricity prices. This method took into consideration the investment costs, including capital repayment. In 2009, the government made further changes in the electricity pricing practices. They include: standardized electricity rates for wind power plants where the country is divided into four districts and each has its specific reference rates for wind generators; equalized electricity prices for commerce and industry; and an electricity rate adjustment plan to increase electricity prices by 2.8 fen/kW·h.

Licensing procedures and channels for dispute resolution: The SERC requires that any unit that wants to engage in the electricity business (including generation and supply) has to obtain a licence. Disputes between units in the electricity market (including companies engaged in power generation, transmission, distribution, supply and other relevant business) are subject to coordination and arbitration by the SERC. If parties disagree with the decision made by the SERC, they may apply for an administrative reconsideration.

Special incentives: The Renewable Energy Sources Law was adopted in February 2005 by the Standing Committee of the National People's Congress and it became effective on 2006-01-01. It was amended later to promote the use of renewable sources for electricity generation.

4.3.1.2. Non-reform related factors

Climate change and energy security: Energy security and climate change concerns require the deployment of all kinds of resources available in the country. In response to these concerns, the central government adopted the energy strategy with the following key elements: optimizing thermal power, orderly developing hydropower, accelerating nuclear power and promoting renewable energy. As a result, the pace of constructing clean energy capacities, including hydropower, nuclear and renewable energy, has been accelerated. As a result, the generation technology mix has become more balanced. This was mainly due to larger investments in baseload hydropower projects in west and south-west China. Nuclear power is also promoted in order to achieve large GHG emissions reductions. As a clean, efficient and reliable energy source, nuclear power capacity is expected to reach about 80 GW(e) to achieve the goal of a 15% share of non-fossil sources in the primary energy mix and a 40–45% reduction in GHG emissions per unit of GDP by 2020 relative to the 2005 level.

The government is committed to promoting new and renewable energy sources. It has announced a range of monetary and non-monetary incentives for promoting renewable energy. These incentives have been quite effective. It is expected that 150 GW of wind and 20 GW of solar capacity will be established by 2020. This will raise the share of clean energy output to 20% and the share of clean installed generation capacity to 40% of the total. Currently, network access arrangements are considered to be a major constraint for the uptake of wind power.

Nevertheless, coal is still the dominant fuel for power generation, accounting for 59% of the newly added capacity in 2012. However, most of this new capacity is based on highly efficient supercritical and ultra-supercritical coal fired power plants. Together with the forced retirement of small old coal fired plants, this has resulted in a significant reduction in annual coal consumption for power generation (by about 82 million tonnes) and in annual GHG emissions (by 165 million tonnes) [83].

Fukushima accident: In response to the Fukushima accident in March 2011, four specific measures were decided by the Standing Committee of the State Council of China: to undertake overall safety inspection of all nuclear facilities immediately; to strengthen the safety practices of all operating nuclear facilities; to review nuclear power stations under construction, and assess and rectify any safety issues identified in the review; and to introduce more stringent procedures for approving new nuclear power projects. These measures are likely to affect the pace of development, the scale of construction and the technological aspects of nuclear power. The policy to promote nuclear power is not expected to change.

4.3.1.3. Insights for policy makers

China is rapidly industrializing and urbanizing. This will lead to increased demand for energy, especially electricity. The technology mix for electricity generation will be determined largely by two factors: climate change and macroeconomic structural change. Electricity production is presently dominated by coal. In order to reduce GHG emissions, the government aims to develop new and clean energy and to improve energy efficiency. Nuclear power has been identified by the country's planners as one of the most effective means to meet these goals. The importance of hydropower and other renewable sources is also increasing.

4.3.2. India

4.3.2.1. Reform related factors

Structure and ownership: The unbundling of the vertically integrated SEBs into separate generation, transmission and distribution segments, combined with the provision of open access to transmission and distribution lines for electricity trading have encouraged large scale investments in power generation capacities. The Electricity Act of 2003 emphasizes competition and the promotion of efficient and environmentally benign policies. These policies have encouraged investors to use the latest, state of the art generation technologies. The national electricity policy and the tariff policy issued by the government, in accord with the provisions of the Electricity Act, also require the deployment of efficient technologies such as supercritical combustion and integrated gasification and combined cycle technologies and the use of large size units in order to increase efficiency and reduce costs.

Inspired by these measures, investors are deploying supercritical generation technology with higher main steam and reheat steam temperatures. This increases efficiency, reduces coal consumption and GHG emissions. Several 660 and 800 MW supercritical units have been planned both in the private and government sectors. Under its ultra mega project policy, the government has already awarded building four stations (each of 4000 MW capacity) using supercritical technology. There are also plans to use ultra-supercritical technology with even higher pressure of 280 bars and 600°C steam temperature which will further improve efficiency and reduce GHG emissions.

The restructuring of the electricity sector has enabled several small, medium and large investors to enter the generation business. Generators can choose to sell electricity either to the distribution companies through long term PPAs or at power exchanges on a short or medium term basis. Whereas the act requires the electricity regulators to determine tariffs for electricity sales to distribution companies, the generators are free to sell electricity to traders or to any consumer by availing open access. These enabling provisions have considerably encouraged investors to engage in the power generation business. The share of private sector in generation has increased from 10.3% in 2003 to 24.3% in 2011.

The Nuclear Power Corporation of India Ltd. (NPCIL) is a publicly owned enterprise. It is under the administrative control of the Department of Atomic Energy. It undertakes design, construction, operation and maintenance of nuclear power stations for electricity generation in pursuance of government schemes and programmes under the provisions of the Atomic Energy Act of 1962. This act permits the NPCIL to form joint ventures with government-owned companies. A joint venture agreement was signed between the NPCIL and National Thermal Power Corporation Ltd., a Government of India enterprise, to implement nuclear power projects in the country. The joint venture company is a subsidiary of the NPCIL. The entire power generated by the NPCIL is fed into the national power grid and is governed by the electricity grid code enforced by the CERC through the regional load dispatch centres. Investments in the nuclear power programme are basically driven by national policies and energy security considerations.

Experience shows that the ownership of the generation business does not really impact the choice of technologies. Both private and public companies look for efficient technologies by conducting thorough technoeconomic analyses. Small investors tend to take up smaller projects using renewable technologies (wind, small hydro, biomass, solar, etc.). Large investors choose the most competitive technologies. As far as nuclear generation is concerned, only a government-owned company can build and own nuclear power stations.

Dispute resolution: With the regulatory system in place, massive investments are being made especially in the generation sector that itself signifies the investors' level of satisfaction. A viable dispute resolution mechanism exists under the Electricity Act. The Appellate Tribunal for Electricity is required to decide on grievances within 180 days. This provision has instilled the confidence of the investors. The act provides full independence and protection for the regulators to act in an unbiased and neutral manner and to strike the right balance between the investors' and consumers' interests. However, the general perception is that the system does not provide complete freedom for the regulators.

Special incentives: To promote renewable energy, the Electricity Act of 2003 requires a specified minimum amount of total consumption to be purchased from renewable sources. This requirement has been actively promoted by some SERCs. The CERC is contemplating to issue guidelines based on which states with surplus renewable energy could issue green certificates that could be bought by distribution utilities unable to purchase the mandated amount of renewable power. Furthermore, states that purchase more than the required percentage of renewable-based power could be rewarded by the government by additional allocation of cheap power from government-owned stations.

Wind technology has increased its share as compared to other renewable technologies after the enactment of the Electricity Act of 2003, from 4228 MW in 2005 to 16 180 MW as on 2012-01-31. This growth is also a result of the government's policy support. The central government provided capital and interest subsidy, accelerated depreciation, tax holiday, concessional customs duty on imports and generation related incentives. State governments also encouraged wind generation by giving land allotment at concessional rates as well as exemptions from sales and electricity duty and tax.

The government has launched a special solar mission to establish India as a global leader in solar energy by providing the policy conditions for technology diffusion across the country as quickly as possible. The mission has set a goal of 20 GW and stipulates achieving the target in three phases by 2022. In order to facilitate the acceptability of grid connected solar power generation, a mechanism of bundling relatively expensive solar power with coal-based power generation is implemented in the first phase. Due to concerns about GHG emissions, greater emphasis is placed on increasing the utilization of renewable energy sources and on the adoption of the latest highly efficient technologies like the supercritical technology for coal fired plants and increased adoption of gas-based combined cycle plants.

4.3.2.2. Non-reform related factors

Demand growth: Triggered by fast economic growth (GDP growth of over 8%/year), electricity demand in India is poised to increase significantly. The Integrated Energy Policy Report of the Planning Commission of the Government of India indicates that the installed electricity generation capacity of about 186 GW will need to increase to 488 GW by 2021–22 and to 960 GW by 2031–32 to keep up with the 9% GDP growth rate. As efficiency is a key aspect of the national electricity policy, the increased use of larger units with efficient generation technologies such as supercritical and ultra-supercritical combustion is likely to be an essential feature of the power expansion programme even in the absence of market reforms.

Climate change and energy security: Energy security and climate change concerns require India to utilize all kinds of resources available in the country. India has limited uranium but substantial thorium reserves that provides an incentive to pursue the national nuclear power programme vigorously and to reach the thorium cycle stage of the programme. However, to pursue this objective, it is essential to have sufficient installed nuclear capacity based on uranium–plutonium fast reactors and then to switch to the large scale use of thorium. The choice of nuclear power generation technologies is not driven by the market reforms. Fuel constraints are impelling India to pursue these technologies to meet its increasing energy demands.

Energy security and environmental concerns also drive the vigorous harnessing of the hydropower potential (150 GW). Renewable sources for producing electricity have gained prominence lately due to their potential to reduce CO_2 emission. The government is committed to tackle climate change and has taken several measures for promoting new and renewable resources. Such measures have proved very effective. Grid connected renewable generation capacity has increased to 23 GW and amounts to about 12% of the total installed capacity in the country. The government has also launched the national solar mission to promote ecologically sustainable growth while addressing the energy security challenge. This will constitute a major contribution by India to the global effort to address the climate change challenge.

Fukushima accident: In the wake of the Fukushima accident in March 2011, opposition by the local population to NPPs has emerged as a major threat to the planned capacity additions. For example, the Kudankulam (2 × 1000 MW(e)) plant was disallowed to be commissioned by the local public.

The Nuclear Power Corporation of India Ltd. has launched a massive campaign to reach out to the people and assure the public about the safety of nuclear power and its economic attractiveness. The Nuclear Safety Regulatory Authority Bill of 2011 was also introduced in the Parliament in September 2011. This bill mainly focuses on the safety aspects of the nuclear technology. It seeks to establish an autonomous regulator, the Nuclear Safety Regulatory Authority, to replace the existing Atomic Energy Regulatory Board. Whereas the Board reports to the Atomic Energy Commission that is responsible for the promotion of nuclear power in the country, after the new bill is passed and becomes an Act, the Nuclear Safety Regulatory Authority would function independently, focusing on safety issues in the nuclear industry [84].

The development of nuclear power is strongly supported in India because for a large and fast growing economy in the context of volatile and uncertain international energy markets, it is perceived to be a national interest to tap all sources of energy and to diversify the energy mix. Nuclear energy enhances energy security. The government intends to ensure that nuclear power is pursued with full regard to the safety, livelihood and security of people. The government also attaches high importance to ensuring that the use of nuclear energy meets the highest safety standards without any compromise in technology, regulations, skilled labour or emergency preparedness. The Fukushima accident is not likely to affect the nuclear power programme, although the pace of its implementation may be slightly slower.

4.3.2.3. Insights for policy makers:

Energy security and climate change concerns have prompted energy planners to rethink the role of nuclear energy in the technology mix. In order to achieve a well balanced portfolio of energy sources and to meet rising demand, the government is placing emphasis on comparatively costlier technologies like nuclear and solar power. In addition, energy conservation and demand side management are also pursued.

4.3.3. Indonesia

4.3.3.1. Reform related factors

Electricity pricing: The tariff setting mechanism determined by the government plays a very influential role in determining the generation technology mix. The power sector is dominated by the PLN. It owned and operated about 85% of the country's generating capacities through its subsidiaries in 2012. It also maintains an effective monopoly over network activities [49]. The government permits PLN to charge electricity tariffs that have only partially been adjusted to reflect changes in the costs of power generation. This has prevented PLN from raising enough revenue to cover its costs. Investment in new, alternative generation capacity has been limited. Instead, the company has to rely on old fossil fuel-based power plants [85].

Licensing: The Electricity Act authorizes the central and local governments to issue licences to electricity business entities that transmit, distribute or trade in electricity. For interprovincial power projects, licences are issued by the central government. For power projects within provinces, licences are issued by the local governments. There is no fee for the licence, but commissioning or performance test certificates are required before it is issued.

Special incentives: Investors intending to develop power projects for public use (not for private use) may receive government support such as import tax and duty exemptions for capital goods. The government also gives support for establishing renewable energy capacities by mandating the PLN to buy electricity generated by such projects at a price set by the government.

4.3.3.2. Non-reform related factors

Government policy: The government's policy has influenced the choice of technologies for power generation. The pro-renewable policy has encouraged sponsors to invest in green technologies.

Size of customers or load: The size of customers also influenced the choice of power generation technologies. For example, small load customers tend to rely on diesel engines and mini or micro hydropower where possible.

The mix and characteristics of customers also influence the choice of generation technologies. Demand peaks between 5 and 10 p.m. local time while industries use more power during daytime. The difference between peak and off-peak loads also influences the choice of technologies for power generation.

Geography and demography: Indonesia has 17 508 islands. Sumatra, Java, Kalimantan, Sulawesi and Papua are big islands, while Bali, Lombok, Bangka and Belitung are of medium size. An island can receive its electricity from one or more electricity systems. Additionally, there are small isolated systems in very small islands.

The features of consumers are quite different across islands. This has some impacts on the investors' choices of generating technologies. In very small islands, for example, diesel generators from a few kW up to 10 MW are normally used. In big islands, however, diverse sources of power generation (such as coal, hydro, natural gas and geothermal power plants) are used.

Fuel supply: Oil was sold to households at subsidized prices until 2006 while industrial consumers had to pay higher prices. This encouraged many industrial consumers to build diesel fired power plants for their own use. Electricity produced by their own plants normally had a lower cost and better quality than electricity supplied by power utilities. However, when oil prices increased sharply and the government reduced subsidies, many industrial consumers stopped using their own diesel power generation and converted to the utilities.

Climate change: As a response to the threat of climate change, the government promotes the use of renewable energy and supports efficiency improvements in power generation. The government launched the first 10 000 MW fast track programme in 2006, most of which involved coal fired power plants. The second 10 000 MW accelerated programme was launched in 2010 and included about 50% renewable energy and 4300 MW geothermal capacities. To encourage the use of renewables, the government allows a direct negotiation process (i.e. without a bidding or tender process) for power generation with a capacity of up to 10 MW. Recently, construction of supercritical steam power plants (2 × 1000 MW) was started that will become operational in 2016.

Fukushima accident: Nuclear energy is on the government's policy agenda because of its attractiveness as an option for dealing with the climate change challenge. The schedule of its start and completion is not yet known.[15] After the Fukushima accident, opponents of nuclear power have intensified their protests. Their views have been widely reported in the media. This has made the task of advancing nuclear power more difficult for the government.

4.3.4. Malaysia

4.3.4.1. Reform related factors

Structure and ownership: Although IPPs were introduced in 1992, there is no competition between the TNB and the IPPs.

Market mechanisms: The government has decided to introduce a competitive electricity market by implementing a three phase process including short (1–2 years), medium (2–4 years) and long term (5 years) phases. In the short term, the aim is to renegotiate PPAs; to remove disparities and harmonize the structure, rates and clauses on cost sharing for excessive supply capacity in PPAs; to operationalize PPAs between TNB's generators and the single buyer; to continue and complete the separation of accounts for the generation branch as well as for TNB's transmission and distribution activities; to open bidding for the development of new capacities; and to ring fence the grid system operation and production planning departments of the TNB. The medium term phase will establish a more transparent and commercial pricing regimes for gas and other fuels; transparent tariff setting processes; and an independent system operator. A technical study to determine the appropriate market structure, to develop the market implementation plan and to conduct a cost benefit analysis is also undertaken in this phase. The long term measures are then expected to result in the introduction of competitive electricity markets by creating governance and regulatory arrangements including open access; the separation of the ownership functions of the TNB; and establishing a market operator, the wholesale electricity market and full retail competition. It is expected that competitive electricity markets will provide price transparency

[15] The government had planned to build an NPP in 1997 but the plan was suspended due to the Asian financial crisis in the late1990s.

(elimination of cross subsidies); allow free entry for new investors in generation and support consumer choice through competition in the retail segment.

Special incentives: The government's target is to generate 17% of electricity from renewable sources by 2030. The Renewable Energy Act was formulated and passed in 2011. A FIT mechanism with a dedicated source of funding (the Renewable Energy Fund) managed by the Sustainable Energy Development Authority is envisaged [54]. A levy is imposed on the electricity tariff for this purpose making customers to fund the FIT mechanism. A dedicated Renewable Energy Implementing Agency is set up with clear responsibilities and powers. Responsibilities and obligations for power utilities and renewable energy developers are also clearly defined. For example, utilities have to take any amount of electricity from renewable sources offered by renewable energy developers. Developers are committed to implement the approved projects on time and within the planned expenditures.

4.3.4.2. Non-reform related factors

Fukushima nuclear power plant accident: Nuclear energy is considered as a centrally planned strategy (a form of regulatory arrangement). This is necessary as there are no market mechanisms yet for this purpose and also because nuclear plants are, by their very nature, capital intensive with long gestation periods. The reasons for introducing nuclear power include constraints in indigenous fuel supply; increased reliance on fuel imports (with the associated exposure to foreign exchange risks) to meet domestic energy demand and the related supply security considerations; environmental issues; problems affecting the uptake of renewable energy sources; market failures; the lack of proper pricing mechanism; absence of a regulatory framework; and the lack of institutional arrangements. The Fukushima nuclear power plant accident has shifted public opinion against nuclear power for electricity generation in the country. The government realizes that more needs to be done to convince the public about the need for nuclear energy. This may delay the construction of the first NPP.

4.3.4.3. Insights for policy makers

In a transition market, decisions about the least cost supply options should be governed by market forces as far as possible and even the fuel type should be determined by the potential bidder. When bidding for a generation plant under such conditions and faced with adequate competition, the bidding party will always seek to achieve the least cost energy mix, including the availability of fuel because the bidder must ensure that fuel is available for operation to earn the revenues needed to pay back at least the capital expenditures. This requires tariffs to reflect the generation costs rather than capacity costs because if an IPP gets most of its payments from capacity charges, it will not be incentivized to ensure the availability of fuel at acceptable costs when selecting the least cost options. The government or the regulator will still have a role in broader oversight to ensure the reliability and security of supply. In a mature market, market mechanisms determine the source, volume and price of electricity to be dispatched. Even in this case, the government or the regulator still have a role to ensure that reliability and security requirements are met.

4.3.5. Philippines

4.3.5.1. Reform related factors

Structure and ownership: The first phase of the reform (1992–2000) encouraged private participation in the generation segment. By 1998, foreign-owned IPPs accounted for around 4800 MW of generating capacity. During the 1990s, over 90% of the new capacity was built by foreign-owned IPPs [86]. In the second phase of the reform (2001 to present), the vertically integrated electricity utility was unbundled, regulatory arrangements including open access to network services were developed and the WESM was created. These changes further promoted private participation in the power sector. Price signals generated from the competitive electricity market act as the main driving force to make new investments in generation. Besides, the pressure from market competition pushes investors to select the most efficient and advanced generating technologies to meet growing demand. In the Visayas region, for example, rapid growth in electricity demand drove up electricity prices, which attracted private investors to build three new coal fired power plants in 2010 and 2011. These plants use low cost and highly efficient circulating fluidized bed technology.

Regulatory arrangements: The EPIRA of 2001 established the ERC to promote competition, encourage market development, ensure customer choice and penalize abuse of market power in the electricity industry. The ERC is also mandated by law to maintain a level playing field in the competitive sectors (generation and supply) and to regulate the transmission and distribution sectors. The EPIRA also mandates the ERC to enforce market share limitations wherein no generation company can own, operate or control more than 30% of the total installed generating capacity of a grid and/or more than 25% of the total national installed capacity. The ERC must also ensure that before a generation company can operate and supply power, it must secure a certificate of compliance with all the appropriate licences or clearances (health, environment and safety) from government agencies and must also comply with the financial standards set forth in the financial guidelines.

Electricity pricing: The ERC adopted the guidelines for the recovery of costs for the generation component of the distribution utilities rates in March 2004. The guidelines seek to enhance the inflow of private capital and broaden the ownership base in the power generation sector and to prepare open access and the operation of the WESM. It establishes the process for determining when the recovery of the generation component of the supply of electricity in the retail rates of a distribution utility should be limited by the rate contained in the transition supply contract, the procedures, standards and criteria for the full recovery of prudent and reasonable economic costs related to the generation component included in the retail rates charged by distribution utilities for the supply of electricity to their captive markets and the guidelines for the approval of new generation contracts by the ERC.

Special incentives: The Renewable Act was enacted in 2008. It incentivizes investors to build renewable power plants. Renewable power producers are entitled to an income tax holiday for seven years after plant commissioning for commercial purposes. They are also assured a guaranteed payment in the form of an FIT.

4.3.5.2. Non-reform related factors

Energy endowment: The Philippines is not endowed with extensive energy resources. The country has to import most of its fuel needed for electricity generation. It is projected that the country will have a severe supply deficit in the coming years. Several companies have invested in coal fired generation to meet growing demand. Some parts of the country are rich in geothermal resources. This has encouraged investors to exploit the geothermal potential in these areas. There are also new investments in wind, solar and hydropower projects stimulated by the renewable energy act and other regulatory incentives.

Political factors: Political factors have a significant influence on the institutional arrangements in the power sector and could impact investors' choices of generating technologies. For example, officials from generation companies are always summoned by the

Congress to explain the reasons for increasing electricity prices. In 2005, a proposal was made in the Congress to withdraw the exemption from the value added tax for IPPs and prohibit the pass-through of the increased costs. This caused a fierce political debate [86].

Public opinion: Public acceptance of a certain technology also plays an important role in the investors' decisions. Several projects have faced challenges in the Philippines that are typical of any other developing country. Despite these challenges, many projects have performed relatively well financially for its sponsors. For example, one of the opposed coal power plant projects has a strong environmental performance and there is evidence that the local community has benefited from the increased tax revenues, and the employment and community programmes sponsored by the project company. The Department of Energy concluded a memorandum of agreement about the benefits for host communities with every investor in the generation sector. Part of the revenue or the electricity generated is allocated for the community from any project in its territory.

Fukushima accident: Even after the 2011 accident at the Fukushima Daiichi NPP, the Philippines is not excluding nuclear power as an option. It still remains a possible alternative for power generation in the future, even though there has been stiff opposition from environmentalists and other social organizations over the past a few years. The Secretary of Energy confirmed that the country should be prepared to embark on nuclear power generation in the future and assured that all necessary safeguards would be established and put in place. The Secretary also pointed out that nuclear power is an option in the future by when safety standards will improve and technology developers will be able deliver much safer facilities. According to the electricity reform agenda, the Department of Energy planned to implement a national nuclear power programme and was targeting to start the operation of a 2000 MW(e) NPP by 2025. However, the schedule had to be delayed as the government has not even started to establish the nuclear programme and is awaiting technological advances for ensuring safety. Following the accident at the Fukushima Daiichi NPP in 2011, the nuclear programme has slowed down.

4.3.5.3. Insights for policy makers

The Philippine Energy Plan for 2009–2030 was developed in response to the challenges confronting the energy sector and to usher changes in the country's energy future. The plan is based on three policy thrusts: (1) ensuring energy security by accelerating the exploration and development of fuel sources, enhancing energy efficiency and attaining full electrification of the country by putting in place reliable power supply and by maintaining a competitive energy investment climate; (2) pursuing effective implementation of the energy sector reform by monitoring the implementation of energy related laws, by amending and passing new laws if necessary and by promoting an efficient, effective and reliable energy sector; and (3) implementing social mobilization through education and information and cross-sectoral monitoring mechanisms among the agencies involved. The country's conventional energy fuels — oil, gas and coal — will remain indispensable in meeting growing energy demand even when alternative energy sources are also pursued. With the passage of the renewable energy act in 2008, policy makers and investors were becoming more focused on developing renewable energy.

4.3.6. Thailand

4.3.6.1. Reform related factors

Structure and ownership: Ownership has no direct impact on the choice of generation technologies. Both public and private power producers have selected efficient and competitive technologies for new plants. In some cases, public power producers were running power plants using non-competitive technologies (e.g. hydro) in order to achieve social, economic and environmental benefits from river basin development such as agricultural activities, flood control and environmentally benign electricity. EGAT — a public electric generating utility — will have the sole responsibility for building NPPs mainly due to security and safety concerns.

Regulatory arrangements: Since the start of the electricity market reform in 1992, there have been several changes in the regulatory arrangements. The amendment of the EGAT act in 1992 was the first step in the process. The act was originally passed in 1968 to establish the EGAT, a combined national generation and transmission utility. The act was amended to terminate EGAT's monopoly status in the generation segment and to allow the private sector to develop, construct and operate power plants. As a result of this amendment, the role of the private sector in the electricity industry has been increasing mainly through the introduction of the IPP and SPP programmes. The former was designed for large scale power projects and directly affected the choice of generation technologies because in order to acquire a licence to supply electricity, IPPs tended to choose competitive technologies (e.g. CCGT, supercritical and ultra-supercritical technologies) that are more suitable for large scale projects than non-competitive technologies. The SPP programme was established to support smaller scale power developments. Its aim was to attract private investors to establish cogeneration systems and small renewable energy projects for electricity production. As a consequence, SPPs would select generation technologies that are quite different from those selected by IPPs.

Although the SPP programme was designed for power projects using cogeneration systems and renewable energy, it has attracted investments mainly in cogeneration (and less for renewables). This is due mainly to the limitations of the SPP regulation such as the unattractive purchase price, costly interconnection requirements and technological risks. Consequently, the VSPP programme was initiated in order to support small renewable projects of less than 1 MW capacity originally, increased to 10 MW later.

Licensing procedures: Prior to the enactment of the Energy Industry Act in 2007, the responsibility for issuing licences for supplying electricity was assigned to the EGAT under the supervision of the EPPO. Critics argued that this could hinder fair competition in generation and discriminate other power producers because while EGAT is responsible for the bid solicitation process, its subsidiary might be one of the competitors submitting bids for obtaining a licence for power generation. As a result, some investors may be prevented from participating in the power sector.

Independence of the regulator from government: The first independent regulatory body — the ERC — was established in 2008 by the Energy Industry Act aiming at ending the interventions of political and interest groups in the regulatory process. The establishment of the ERC was also expected to separate the regulatory functions from the hierarchy of policy making entities. This was expected to promote the autonomy, transparency and creditability of and public participation in the electricity sector decision making. However, the ERC lacks independence and regulatory authority. There are still unclear lines of authority in the consultative relationships between the ERC, the MOE and the EPPO. It is unclear how they relate to each other in the operation of the regulatory regime [87]. The lack of independence and regulatory capacity has directly resulted in lower investor confidence. This subsequently necessitated the provision of generous terms for PPAs. This means that regulatory independence does in fact have a direct influence on the attractiveness of the investment climate in the electricity industry. Nonetheless, the impact of such factors on the choice of generation technologies is not yet known because the regulator has only recently assumed its true regulatory functions.

Special incentives: Efforts have been made to move away from the use of fossil fuels for electricity production by increasing the use of indigenous renewable energy resources in order to enhance the security of electricity supply and to reduce environmental impacts. However, it is widely acknowledged that renewable energy is currently commercially unviable as compared with conventional energy sources. The government has therefore initiated measures to help improve the commercial viability of renewable energy. The measures include pricing subsidies (known as adder provision) and financial incentives through investment subsidies and the provision of soft loans [88]. The adder provision is a mark-up on top of the normal price received by power producers when they sell electricity to the utilities [89]. The amount of the adder provision varies depending on the type of renewable energy used. This scheme is initially tried for a period of seven years from the start of commercial operation.

4.3.6.2. Non-reform related factors

Energy security: Thailand has limited domestic energy resources. Recently, energy security concerns have moved to the forefront of the country's energy policy debate. The electricity industry is heavily dependent on imported natural gas for power generation. In addition, due to the uncertainty of oil prices in the future, oil imports for electricity production increases fuel price risks investors may be unwilling to take. Importing more oil would also reduce energy security. Hence, the substitution of other energy resources for natural gas and oil is a way to enhance energy security. In order to diversify energy sources used for generating electricity, the government planned to establish more coal fired power plants. However, in recognition of concerns about GHG emissions, the share of coal-based electricity is limited to only 17% in 2030 [90].

Climate change: Renewable energy is an attractive option for reducing the use of natural gas and oil in power production. This option will allow the government to meet its policy goals of diversifying energy supply, reducing GHG emissions and promoting clean energy in accordance with the Renewable Energy Development Plan 2008–2022. However, this choice is less appealing because renewable energy is commercially less attractive than conventional energy sources. In responses to measures to improve the commercial viability of renewables, the share of renewable energy-based generation capacity is projected to increase from 2.5% in 2010 to 7% in 2030 [90].

Energy efficiency: With the aim of promoting efficient energy utilization and electricity production, the government has provided incentives to promote the use of cogeneration systems producing electricity and steam. Under the power development plan, the generating capacity of cogeneration systems is expected to increase to nearly 7500 MW, accounting for 11% of the total installed capacity in 2030.

Demand growth: In order to meet the growing demand for electricity, significant generating capacity will be required. Despite the increased additions of renewable energy and cogeneration systems (as noted above), the industry will still have insufficient generating capacity. Nuclear power therefore becomes an attractive option to meet rising electricity demand. It can also contribute to improved security of electricity supply, enhanced efficiency and reliability of the power system, reduced dependence on imported fuels and lower GHG emissions [90].

Based on the Power Development Plan of 2010, the share of nuclear energy in the technology mix is unlikely to reach more than 10%. The first nuclear power project with a generating capacity of 1000 MW(e) is expected to be commissioned in 2020. By 2030, nuclear power capacity is projected to reach 5000 MW(e), accounting for nearly 7% of the total generating capacity.

Fukushima accident: Another non-reform related factor is the NPP accident in Japan. It has raised concerns about nuclear power in several countries and led to a thorough review of the plan of building NPPs in Thailand. According to the plan, five 1000 MW(e) NPPs are to be built in the 2020s but if the plan is disrupted, they must be replaced with 13 coal fired plants and one natural gas unit. Accordingly, the Power Development Plan of 2010 will be carefully reviewed with emphasis on other energy options.

4.3.6.3. Insights for policy makers

Energy security, environmental concerns, the independence of the regulator and nuclear safety concerns are crucial factors for achieving the targeted generation mix. Continued high level dependence on natural gas for electricity production has reduced energy security. The sector's ability to add more coal fired power plants is limited by environmental concerns. Renewable energy and nuclear power are therefore attractive options for the Thai electricity industry in the future.

For renewable energy, special regulatory incentives have been provided to attract investments from private sources. However, in order to ensure investor confidence, the independence of the regulator is essential. For nuclear energy, it was expected that the first plant would be commissioned in 2020 and its share in the technology mix would increase to about 7% by 2030. Concerns about nuclear safety have intensified after the Fukushima accident and have delayed the implementation of the nuclear power development plan. If the government fails to gain public support for nuclear power, it will need to be replaced by other technologies.

4.3.7. Pakistan

4.3.7.1. Reform related factors

Structure and ownership: The restructuring of the power sector and open access to the transmission and distribution networks have encouraged private investors to participate in the generation segment in the form of SPPs and IPPs. The share of the private sector in electricity generation has increased from 19% in 1997 to 39% in 2010. SPPs and IPPs supply electricity to distribution companies under PPAs. Prior to the reform, the generation mix was dominated by hydropower. After the reform, most private investors decided to build thermal power plants (TPPs) due to their lower investment costs and shorter construction times.

Special incentives: The government encourages electricity production from renewable sources. The country's first renewable energy policy was introduced in 2006 by the alternate energy development board and was updated in 2011. It obliges the NTDC and the Central Power Purchasing Agency to purchase electricity from renewable power plants. The policy permits investors to generate electricity using renewable resources at one location and receive an equivalent amount for their own use elsewhere in the grid at their own cost of generation plus transmission charges (wheeling). The policy also lays down simplified and transparent principles of tariff determination and facilitates projects to obtain CO_2 credits for avoided GHG emissions. Thirteen wind power projects were proposed by private investors and the NEPRA has granted generation licences for seven projects. In addition, the NEPRA provides guaranteed rate of return on power projects that use domestic coal and bagasse. Recently, the NEPRA encouraged the sugar industry to participate in power production by using cheap indigenous bagasse by guaranteeing an 18% rate of return. The NEPRA also encourages the use of domestic coal for power generation where the guaranteed rate of return is 20%.

4.3.7.2. Non-reform related factors

Energy endowment: The government intends to promote electricity generation from indigenous resources including hydro, local coal and renewables. To achieve this objective, several regulatory incentives are offered to the investors such as an internal rate of return of 20% for using coal from the Thar region to firms achieving financial closure before 2015-12-31, exemption from customs duties on import of mining equipment and machinery including vehicles for on-site use, exemption from withholding tax on procurement of goods and services during project construction and operations, exemption for 30 years from other levies such as special excise duty, federal excise duty, Workers Profit Participation Fund and Workers Welfare Fund. In hydropower projects, hydrological risks are borne entirely by the power purchaser, tariff adjustment due to cost variation are based on four tariff reopeners: geology in the tunnel, civil works, hydraulic steel structures, mechanical and electrical works, and resettlement cost.

Demand growth: The Integrated Energy Plan of 2009 envisaged an economic growth of 5%/year up to 2023. Based on this growth target, the energy plan envisaged 55 000 MW of total installed capacity in 2023 compared to 20 264 MW in 2010. This capacity expansion is expected to be met primarily by the exploitation of indigenous resources including hydro (17 392 MW), local coal (10 000 MW) and other renewables (wind and solar 17 400 MW). The plan also envisaged a nuclear capacity of 4345 MW by 2023.

Fukushima accident: After the Fukushima March 2011 NPP accident, the PAEC started an extensive programme to revisit the safety plans of its three operating NPPs and took measures to ensure the safety of their design and operation. Separate emergency preparedness and response plans were prepared for operating NPPs. In principle, the PAEC is committed to operate the existing NPPs and to build more plants in future.

4.3.7.3. Insights for policy makers

The power sector reform process started in the 1990s still continues. The government needs to take steps for completing the privatization process. Institutions need to be strengthened and coordination between stakeholders should improve. To achieve the desired electricity generation mix, several suggestions were made to the policy makers: vigorous efforts to tap indigenous coal reserves for power generation, the use of renewable energy resources, enhanced use of abundantly available hydropower resources, increased oil and gas exploration and production, expeditious completion of the Iran–Pakistan gas pipeline, using liquefied natural gas as an alternate fuel, accelerated development of a liquefied natural gas terminal, lowering transmission and distribution losses and measures to bring prices paid by consumers into parity with the true costs of generation. These initiatives would enhance the diversity and security of power supply and promote the provision of adequate amount of affordable and sustainable electricity.

4.3.8. South Africa

4.3.8.1. Reform related factors

Structure and ownership: It is a widely held view that large capital intensive assets (such as large coal and nuclear plants) are better candidates for state funding and ownership while smaller and more incremental technologies like gas and renewables are easier to fund by the private sector. This has resulted in Eskom's taking the lead in coal and nuclear projects and the private sector in renewable projects.

Regulatory arrangements: Earlier regulatory arrangements mainly focused on supplying electricity at the lowest possible cost. As a result, the generation mix mainly comprised of coal, hydro and natural gas. Coal has traditionally dominated the country's generation mix because of the availability of copious amounts of indigenous coal reserves at relatively low prices. Pumped water storage is mainly used to meet peak demand but available sites for such plants are limited. Natural gas fired power plants therefore constitute important elements of the capacity mix. Recently, the government has included GHG emissions reductions as a distinctive factor in the design of regulatory arrangements. This has shifted the generation mix towards renewables and nuclear power.

Electricity pricing: Historically, private investors have shown little interest in power projects because of the generally low electricity prices and the lack of appropriate regulatory arrangements to recover their costs.

Independence of the regulator: Private investors have continually expressed frustration with the government departments over the delays in finalizing the PPA documentation and creating the enabling environment for private investments. This situation is expected to improve as the REFIT scheme gets implemented and the private sector begins to have a meaningful role in the generation sector.

The regulator fully implemented the electricity pricing policy and the respective tariff calculation rules. Tariff increased sharply: by 34% in 2009, 25% in 2010, 25% in 2011 and 25% in 2012. It remains unclear if and when the regulator will make use of its independence and fully implement its governing policy.

4.3.8.2. Non-reform related factors

Energy endowment: The historic primary driver for technology choice has been the country's energy resource endowment. South Africa is a relatively arid country and has limited hydro resources. It has rather limited reserves of oil and natural gas but copious coal reserves. As a result, the power sector is dominated by coal.

Economies of scale: The size of the electricity system (currently approximately 43 000 MW) has also influenced the choice to build large coal fired power plants rather than smaller ones due to the perceived scale benefits.

Energy security and climate change: Energy security related to water availability (for cooling and fluidized gas desulphurization), the export of goods produced by using CO_2 intensive electricity and political pressure about climate change are shifting the generation mix away from coal towards nuclear and renewables. The government also fosters job creation and the development of an advanced manufacturing industry to support the economy and help equalize the current account deficit. This has driven recent decisions towards a fleet approach to nuclear and renewables to enable the local manufacturing sector to commit capital to the factories necessary to produce components for the power plants.

Rural electrification: Rural electrification and off-grid power drive the use of solar panels, solar water heaters and small wind turbines.

Fukushima accident: In the light of the Fukushima accident, the government made a commitment to ensure that future nuclear programmes in the country take full account of the lessons learned from this accident. As indicated in the Integrated Resource Plan for Electricity 2010–2030, new nuclear capacity of 9600 MW is planned to be built by 2029.

4.3.9. Turkey

4.3.9.1. Reform related factors

Structure and ownership: The role of private companies in the power sector has increased steadily since the initiation of the reforms in 2001. Between 2001 and 2010, electricity production by private companies increased from 30% to 55% of the total output. Capacities added by private companies during this period comprised 10 GW natural gas, 2.8 GW coal, 1.5 GW wind energy and 2.5 GW hydropower plants.

Special incentives: The renewable energy law was enacted in 2005 and it was further strengthened in 2011 to promote the uptake of renewable sources for power production. Two major incentives are provided to encourage new investments in renewables including FITs and regulated purchase obligations for distribution companies to buy electricity from certified renewable power producers. The FIT is only a transition instrument and the government is planning to replace it with a market-based mechanism.

There are also other incentives for renewable energy such as exemption from annual licence fee payments, priority in connecting to the transmission or distribution grid and discounted land use fees. These mechanisms are envisaged to facilitate the development of renewable power plants particularly small hydro and wind installations. Inspired by these measures, many investors apply for licences to build power plants using these renewable sources. Further price incentives are offered to renewable power producers who use domestically manufactured mechanical and/or electromechanical parts in their power plants.

There are also some incentives for nuclear power projects such as the guaranteed availability of sites for building power plants and purchasing power at a pre-agreed price. These incentives are considered essential for attracting investments in nuclear power projects.

4.3.9.2. Non-reform related factors

Energy efficiency: The government is well aware of the need to reduce the country's energy import dependence. Improving energy efficiency is viewed by the government as a means of reducing such dependence. An energy efficiency law has been enacted and several programmes have been undertaken to improve energy efficiency.

Demand growth: Rapid economic growth is another factor that influences the development of the power sector. Demand for electricity has grown significantly over the past two decades driven by rapid economic growth. The growth rate averaged 8.1% over the period 2001–2007 but reduced to 2% in 2008–2009 due to the impacts of the global financial crisis on the Turkish economy. In 2010, electricity demand rose again. It is projected to increase by

7%/year in the coming years. This rapid demand growth will require timely new investments in generation capacity.

Fukushima accident: The Turkish government has signed an agreement with the government of the Russian Federation in May 2010 to construct four 1200 MW(e) units. This will be Turkey's first NPP. The TETAS has guaranteed the purchase of 70% of the electricity generated by the first two units and 30% from the third and fourth units in the form of a 15 year PPA at the price of 12.35 US cents/kW·h. The remaining power will be sold in the open market by the producer.

The Fukushima 2011 NPP accident will not prevent Turkey from progressing with the introduction of nuclear energy. The government strongly supports the nuclear energy programme. The Russian project company has already started working on the project by preparing the environmental impact assessment. Construction is expected to start in 2017 [91].

4.3.9.3. Insights for policy makers

Accelerated economic growth, increasing population and improving living standards have driven up the demand for electricity. Between 2000 and 2007, electricity consumption increased by 50%. It is expected that the temporary decrease in power consumption during the economic downturn in 2008–2009 will not influence longer term trends and that — based on conservative projections — electricity consumption will double by 2020. This will require at least a doubling of the installed generation capacity.

The generation mix to meet this demand is likely to be constrained by several factors including energy efficiency, climate change, system integrity and security of supply. The Electricity Market and Security of Supply Strategy of 2009 foresees the following key developments in the generation mix: (1) significant development of natural gas, new coal and lignite fired power plants that are undoubtedly necessary to ensure security of supply but raise major concerns about CO_2 emissions; (2) increased energy efficiency; (3) diversification of energy sources, technologies and supply routes; and (4) more than doubling of electricity production from renewable sources to at least 30% of the electricity supply by 2023, mainly from hydro and wind power plants. These vast investment needs will require a robust regulatory framework and effective price signals to ensure timely and adequate investments.

4.3.10. Kenya

4.3.10.1. Reform related factors

Structure and ownership: Prior to the reform, the electricity industry in Kenya was dominated by hydropower. After the reform, private investments were encouraged in the form of IPPs. Most private investors built oil fired power plants characterized by lower capital costs and shorter implementation periods as compared to other conventional technologies. After 2000, private investors began to build renewable power plants, especially geothermal and wind. This was mainly motivated by regulatory incentives such as CO_2 credits and FITs.

Generation pricing: Electricity prices for generators are regulated by the ERC. Prices are determined to ensure investors a moderate rate of return on their investments. The ‘take or pay’ clause in the PPAs has encouraged investments in generating technologies with high operational costs such as oil fired plants.

Network pricing: Transmission prices are determined according to the power plant's distance from the main grid. In general, most proposed power plants are situated within a reasonable distance from the grid although there are also exceptions. For example, the proposed 300 MW Lake Turkana wind farm (in Marsabit, a remote area in the north) has been deemed very attractive despite its large distance from the existing grid due to its high capacity factor thanks to superb wind regimes and the minimal need to displace people in the remote and sparsely populated area. The high output from the project is more than enough to compensate the huge transmission investment.

Special incentives: Several measures have been used by the government to encourage investments in renewable power plants. A FIT scheme was introduced in 2008 to promote the development of renewable energy. Many investors have expressed interests in building renewable plants. A large proportion of the proposals made by private investors is wind power plants.

4.3.10.2. Non-reform related factors

Energy endowment: Kenya has abundant geothermal resources. The government has implemented several measures to enhance the harnessing of this resource for power production. The Geothermal Development Company was formed to prepare a resource appraisal with adequate financial support from the government. Several private investors have expressed interest in investing in geothermal power plants. KenGen, the largest generator in the Kenyan power system, is also implementing a long term geothermal strategy and aims to build several large scale geothermal plants. All these efforts are likely to increase the contribution of geothermal power to the generation mix.

Energy security: Ensuring adequate electricity supply has been a challenge for a long time. The power system has been beset by the slow pace of capacity additions that led to extensive load shedding and procurement of emergency power as a short term measure. This has usually been followed by calls for fast track construction of new plants. Medium speed diesel power plants are implemented on a fast track basis to meet immediate demand. One of Kenya's neighbouring countries, Ethiopia has huge hydropower resources that are currently being developed at a large scale. A proposal to build an interconnection to import power is at an advanced stage. However, there is a debate about how to account for the imported power in the Kenyan power supply system. Proposals have been advanced to maintain a reserve capacity equivalent to the amount of imported electricity in order to have guaranteed security of supply in case of unforeseeable events in Ethiopia.

Demand growth: Demand for power in Kenya has increased faster than economic growth. The planning for future capacity additions has therefore been taken up more seriously. Comprehensive approaches are implemented to select technologies that will meet future power demand for all sectors in the economy at the lowest possible cost. This planning was undertaken by experts from the power sector under the leadership of the regulator (the ERC). High projections for electricity demand have provided incentives to invest in geothermal power as this is a locally available resource. Future options also include other resources that have not been utilized in Kenya before, namely coal, natural gas and nuclear power. Fuel for these technologies would need to be imported as Kenya has no known reserves of the required natural resources.

Climate change: The power development plan is updated annually based on demand projections for the following 20 years. Generation and transmission infrastructure to serve the projected demand is also assessed. The power development master plan guides the investment decisions in power projects. The plan considers all possible power generation options and selects the least cost mix. Generation producing GHG emissions is penalized in a way that increases the electricity cost and disadvantages dirty technologies as their economic ranking is lowered by the CO_2 tax, giving way for the adoption of cleaner technologies for implementation. Renewable technologies emitting minimal or no GHGs qualify for CO_2 credits earned from the commencement of the operation. The additional earnings is an advantage for generation technologies without CO_2 emissions.

Clean power technologies include wind, solar, biomass, hydro, biofuel and nuclear. They generate electricity with a smaller environmental footprint. They benefit from environmental finance through the generation of CO_2 credits available for projects that are proven to be additional or beyond business as usual according to the rules for the CDMs under the Kyoto Protocol of the UNFCCC (except nuclear energy). Power project investors are now keen to finance generation with clean technologies. This has led to a heightened interest by both public and private generators in renewable energy and clean projects. Several of these projects have been approved for CO_2 credits under the CDM and more proposals have been made for future implementation. Geothermal, bagasse and wind projects were earmarked for CO_2 credits with two projects already earning credits.

In order to meet the growing power demand, to diversify the energy supply mix and to mitigate GHG emissions, nuclear power was incorporated into the country's future generation mix. The least cost power development plan is the blueprint for the electricity system expansion for the next 20 years. The first nuclear plant (1000 MW(e)) is scheduled to start in 2022 and has already received government support. The Nuclear Electricity Project Committee was established. It is working on the framework for the programme. Kenya targets to have at least 4000 MW(e) of nuclear capacity by 2031 that would constitute about 25% of the total generating capacity.

Fukushima accident: The Fukushima 2011 NPP accident has divided experts on the suitability of nuclear power for the country. Those opposing the programme feel that the country is not adequately equipped in terms of human capital to either operate nuclear infrastructure or handle a crisis that might occur in case of a nuclear event. However, the Nuclear Electricity Project Executive Committee has defended the nuclear programme by stating that it is still in its infancy and there are plans to develop human capacity, legal and regulatory frameworks, security and safeguards arrangements, and all other elements pertaining to a nuclear programme. The chairman of the committee assured that the national government guarantees that the highest standards are maintained for every aspect of the nuclear programme. It is also expected that the lessons learned from previous nuclear accidents, including the one at the Fukushima Daiichi NPP in 2011, would inform future developments in nuclear plant design, codes of practice, waste disposal methods and emergency response programmes.

4.3.10.3. Insights for policy makers

In order to achieve the target generation mix for optimal power system operation in Kenya, the following incentives are proposed for adoption by policy makers: tax breaks for target generation types to encourage investments; government guarantees for public and private investors in the targeted generation technologies in order to enhance financing conditions; fuel market stabilization through the use of forward contracts and other market mechanisms to minimize monthly tariff variations caused by fuel price fluctuations in international markets; facilitation of acquisition of land and other infrastructure required for power investments; and enhancement of the legal and regulatory framework to meet internationally approved standards including full independence of the regulator to enhance investor confidence. In introducing nuclear energy, the country will benefit from bilateral agreements to enhance human resources and technical capacity building for managing nuclear technologies.

The national energy strategy and the selection of electricity supply options are likely to be influenced by several factors. The country has large geothermal resources but in order to use it for power production sustained government funding is needed. The adoption of nuclear energy will be determined by the citizens' perception and their confidence in the government's ability to manage a nuclear power programme. The Fukushima accident is likely to influence the decision. Future power supply options from coal, oil and natural gas are likely to be affected by international fuel prices. Financing options available for the electricity infrastructure will greatly influence the level of investments. The existing national grid covers only a small part of the country and the transmission and distribution systems are also characterized by technical weaknesses. There is therefore a need for increasing the pace of transmission system expansion to remote areas as well as to reinforce the existing grid.

4.4. SUMMARY

The country case studies reveal the wider implications of electricity market reforms in various countries. They show that while the reform related factors have influenced the investors' choices regarding the technology mix in some countries, non-reform related factors have played an equally important, and in some cases even bigger, role in shaping those decisions.

The main findings from the case studies of mature as well as transition and potential markets are summarized in Tables 8–11.

TABLE 8. THE INFLUENCE OF ELECTRICITY MARKET REFORMS ON THE TECHNOLOGY MIX IN MATURE MARKETS

Australia	**Industry structure:** A growing trend towards vertical reintegration between generators and retailers has been observed in recent years. This practice is likely to deter investments by new entrants. **Market mechanisms:** Price signals generated from the NEM are considered to be the main driver for making new investments in generation. Around 13 850 MW of new generation capacity was added in the period 1999–2011. **Special incentives:** Regulatory measures (such as MRET) have led to a rapid development of renewable energy in power generation.
New Zealand	**Industry structure:** In recent years, there has been an increasing trend towards vertical integration between generators and retailers. This practice hinders vertically non-integrated generators from entering the market. **Market power:** The lack of geographical diversity of generation companies and imbalanced generation technology mix provide scope for existing large companies to exercise market power. This may undermine the confidence of independent investors and deter them from participating in the electricity sector. **Market mechanisms:** Price signals generated by competitive markets have delivered sufficient investments in new capacities. Most of the new investments has been in wind, geothermal and natural gas generation technologies.
UK	**Industry structure:** The NETA/BETTA arrangement encourages vertical integration between generators and retailers but hinders small vertically non-integrated investors entering the market. **Market mechanisms:** Motivated by relatively high spot prices and the provision of capacity payments, the market has attracted significant investments over the period 1990–2001 especially in gas fired capacity. Since 2001, the NETA/BETTA arrangement has improved competition in the wholesale market and consequently lowered spot prices. Lower prices, together with the termination of capacity payments in the new wholesale market arrangements have discouraged new investments in the 2001–2010 period. **Network pricing:** The current network pricing mechanism encourages investors to locate new capacities close to existing networks and centres of demand. This practice makes connection of renewable sources quite expensive. **Retail competition:** Competition in the retail segment was extended to all customers by 1999. Since then, retail prices have largely followed the movements in wholesale prices and the costs of supply. This link favours investments in generation capacities for which costs vary in line with wholesale prices. **Special incentives:** Renewable energy has been supported by the ROCs scheme. This scheme accelerated investments in renewables after 2000, particularly in onshore and offshore wind capacities after 2005.

TABLE 8. THE INFLUENCE OF ELECTRICITY MARKET REFORMS ON THE TECHNOLOGY MIX IN MATURE MARKETS (cont.)

Germany	**Market mechanisms:** Price signals generated by the electricity markets have delivered sufficient investments in new capacities. Yet there has been a growing concern about the capability of the current market arrangements to ensure adequate supply in the future due to low electricity prices caused by the increasing uptake of renewable power sources. **Network constraints:** Network constraints have increasingly become a bottleneck for the uptake of renewable energy. Some generators are not able to get their power into the system due to the lack of interconnections. **Special incentives:** The FIT scheme has made renewable energy sources attractive compared with conventional energy.
Lithuania	**Regulatory arrangements:** Current licensing procedures favour financially strong companies. **Market mechanisms:** With the initiation of the electricity market in 2010, decreasing electricity prices have discouraged potential investors. **Special incentives:** Special incentives are provided to attract investments in renewable energy.
Poland	**Ownership:** The domination of the State Treasury in the ownership of electricity companies tends to favour power companies using domestic coal and lignite. **Market mechanisms:** Price signals from the electricity market are distorted by the uneven distribution of generation capacity between the south and the north, and network constraints between the two regions. **Special incentives:** Legal requirements (green certificates) were established to promote renewables.
USA	**Network constraints:** The lack of interconnections between the renewable resource centres and the demand centres creates potential barriers for the uptake of renewable generating technologies. **Special incentives:** The loan guarantee programme of the Department of Energy for the nuclear industry was authorized by the Energy Policy Act of 2005. This programme covers up to 80% of the total construction costs. Considerable support is also provided for renewable energy at the state level. This support has delivered a significant amount of investments in renewable capacities.
Chile	**Special incentives:** Legal procedures were established to include renewables in the energy supply mix.
Colombia	**Market mechanisms**: The current market mechanism in the form of a pool market favours large power companies that are able to assemble a diversified technology portfolio and to integrate with retail businesses.

TABLE 9. THE INFLUENCE OF NON-REFORM RELATED FACTORS ON THE TECHNOLOGY MIX IN MATURE MARKETS

Australia	**Energy endowment:** The country is endowed with abundant, high quality and diverse renewable and non-renewable energy resources. Copious coal reserves made coal fired generation the dominant technology to produce electricity in the country. Besides, there are large and widely distributed renewable energy sources. This suggests that Australia has considerable potential to address the climate change challenge by using renewable energy. **Climate change:** Growing government awareness about the seriousness of climate change has put the transformation of the power sector at the centre of the transition to a low GHG emissions economy. A number of measures have been adopted at both national and state levels, to support the development of low GHG emission technologies. As a result, gas fired and wind generation have attracted the bulk of new investments while relatively less interest has been witnessed in coal generation. **Demand growth:** There has been a long term trend of declining energy intensity of the economy. It has slowed down the rate of generation capacity expansion but it did not affect the investors' choice of generation technologies. **Policy uncertainty:** The lack of bipartisan political agreement on CO_2 pricing is creating uncertainty that has a direct influence on investment decisions. **Fukushima accident:** Nuclear power is a highly contentious issue. The general public sentiment is anti-nuclear. The Fukushima accident has further increased public concerns about nuclear power.
New Zealand	**Energy endowment:** The country is endowed with abundant renewable energy resources especially hydro, wind and geothermal sources. Hydroelectric generation has been dominating the energy system for almost a century. The relative importance of hydropower gradually decreased by the mid-1990s as most of the hydroelectric potential had already been utilized. The importance of gas, geothermal and wind generation has increased in recent years. **Climate change:** The government has a strong commitment to reduce GHG emissions. An ETS was introduced and became operational in 2008. It was expected to attract investments in renewable capacities. **Fukushima accident:** Historically, public opinion strongly opposed nuclear power. The Fukushima 2011 NPP accident has further deepened the anti-nuclear sentiment in the country.
UK	**Climate change:** The UK government's growing interest in climate change policy and the introduction of the EU ETS has discouraged investments in coal and oil fired generating technologies. Instead, renewables and nuclear have been identified by the government as viable options for reducing GHG emissions. **Policy uncertainty:** Comments by potential investors frequently indicate a degree of uncertainty over the future of non-market incentives dependent on government policy. **Fukushima accident:** Planners have promoted new nuclear plants as a more dependable source of electricity that can facilitate reaching the government's GHG emissions reductions targets. Keeping nuclear power as part of the capacity mix was sustained even after the Fukushima accident.
Germany	**Fukushima accident**: The accident broadened and solidified the anti-nuclear attitude of the public and politics. As a consequence, political consensus has emerged on the nuclear energy phase-out programme.
Lithuania	**Climate change:** The government has shown a growing interest in climate change policies. A number of policy measures have been adopted to promote the use of renewable sources in power generation and had a positive impact on investments in renewable capacities. **Energy security:** All of the natural gas and oil consumed in the country is imported from the Russian Federation making it very vulnerable to interruptions of the fuel supplies. The development of nuclear power was promoted by the previous government as a means to address the energy security challenge. **Fukushima accident:** The accident has had only a slightly negative impact on the public opinion about nuclear energy. However, the elections and the public referendum in November 2012 about the new nuclear plant created uncertainties regarding the future of nuclear power.

TABLE 9. THE INFLUENCE OF NON-REFORM RELATED FACTORS ON THE TECHNOLOGY MIX IN MATURE MARKETS (cont.)

Poland	**Climate change:** The EU environmental policy has proven to be very challenging for potential investors in the power generation sector. **Fukushima accident:** The 2011 NPP accident has had little impact on the country's nuclear programme.
USA	**Social attitudes against renewables:** Increasing local resistance to certain renewable technologies (especially wind) has become an important barrier to their uptake. **Fukushima accident**: The 2011 NPP accident has slowed down the development of nuclear power.
Chile	**Energy endowment:** The country's generation mix is influenced by its resource endowment: abundant hydro and renewable resources, a limited amount of yet unexploited coal reserves. Most electricity is generated from hydro. The share of non-conventional renewable electricity directly depends on the measures adopted by the government to promote it. A significant amount of fossil fuels is imported for thermal generation. Decreasing natural gas imports have led to increasing use of diesel and liquefied natural gas for power production. **Climate change and energy security:** The uptake of renewable energy is viewed by the government as a means to reduce GHG emissions and to diversify sources for power production.
Colombia	**Energy endowment:** The abundance of indigenous hydroelectric resources has resulted in its dominance in the capacity mix. **Climate change:** The country is viewed as a net power exporter and investors have the incentives to build generation facilities not only to meet local but also regional demand primarily from clean sources. The government has established targets for promoting energy efficiency and the uptake of renewable resources. **Energy security:** Generation portfolios are diversified mainly by the inclusion of firm energy (hydro plants with reservoirs and thermal plants) in order to address the energy security challenge.

TABLE 10. THE INFLUENCE OF ELECTRICITY MARKET REFORMS ON THE TECHNOLOGY MIX IN TRANSITION AND POTENTIAL MARKETS

China	**Ownership:** The reform has resulted in a diversification of investments in the generation sector. **Special incentives:** The Renewable Energy Sources Law became effective on 2006-01-01. It was amended in April 2010 to promote the use of renewable resources for electricity generation.
India	**Ownership:** Ownership of the generation business has not noticeably affected the choice of technologies. Both private and public companies tend to invest in efficient technologies. Smaller investors find smaller projects such as renewables (wind, small hydro, biomass, solar, etc.) more attractive, whereas large companies prefer more competitive technologies. Nuclear capacity has remained in the governmental domain. **Special incentives:** Special incentives have been provided by the government to support the deployment of renewable capacities, especially wind and solar power plants.
Indonesia	**Electricity pricing:** Price subsidies are widespread. This has prevented the power company (PLN) from raising enough revenue to cover its costs. Investments in new generation capacities have therefore been limited. **Special incentives:** Investors intending to develop power projects for public use are eligible to receive government support in the form of import tax and duty exemptions for capital goods. The government also provides support for renewable energy projects.
Malaysia	**Special incentives:** The government plans to achieve 17% of electricity generated from renewable sources by 2030. Several measures have been adopted to achieve this objective, including an FIT scheme and regulated purchase obligations.
Philippines	**Structure and ownership:** Restructuring the power sector encouraged private investors (especially foreign investors) to participate in the generation business. With the introduction of market competition in 2001, competitive market pressure pushed investors to select the most efficient and advanced generating technologies to meet growing demand. **Special incentives:** The renewable energy act was enacted in 2008. It incentivizes investors to build renewable power plants.
Thailand	**Structure and ownership:** Ownership has no direct impact on the technology choice. Both public and private power producers have selected efficient and competitive technologies for new plants. In some cases, public power producers operate power plants employing non-competitive technologies (e.g. hydropower). **Licensing procedure:** Before 2007, the EGAT was responsible for issuing licences for supplying electricity. This hindered fair competition in generation and discriminated against other power producers. **Independence of the regulator:** The lack of independence and regulatory capacity has directly resulted in lower investor confidence. The impact of these factors on the choice of generation technologies is not yet known because the regulator has only recently assumed its regulatory functions. **Special incentives:** The government has initiated measures to promote the uptake of renewable energy. These measures include pricing subsidies and financial incentives through investment subsidies and soft loans.
Pakistan	**Structure and ownership:** The restructuring of the power sector and open access to transmission and distribution networks have encouraged private investors to participate in the generation segment in the form of SPPs and IPPs. Most private investors decided to build TPPs. **Special incentives:** The government encourages electricity production from renewable sources.

TABLE 10. THE INFLUENCE OF ELECTRICITY MARKET REFORMS ON THE TECHNOLOGY MIX IN TRANSITION AND POTENTIAL MARKETS (cont.)

South Africa	**Structure and ownership:** Large capital intensive assets (such as large coal and nuclear plants) are better candidates for state funding and ownership while smaller and more incremental technologies like gas and renewables are easier to fund by private investors. This has resulted in Eskom's taking the lead in coal and nuclear projects and the private sector in renewable projects. **Regulatory arrangements:** Earlier regulatory arrangements mainly focused on supplying electricity at the lowest possible cost. As a result, the generation mix mainly comprised of coal, hydro and natural gas. Recently, the government has included GHG emissions mitigation as a distinctive factor in the design of regulatory arrangements. This has shifted the generation mix towards renewable and nuclear plants. **Electricity pricing:** Historically, private investors have shown little interest in power projects because of the low electricity prices and the lack of appropriate regulatory arrangements to recover the cost of new power plants. **Independence of the regulator:** Private investors have continually expressed frustration over the lack of independence of the regulator.
Turkey	**Structure and ownership:** The reform has encouraged private participation in the generation segment. Capacities added by the private sector include natural gas, coal, wind and hydropower plants. **Special incentives:** A mix of tax and non-tax incentives has been provided by the government to promote the development of generation from renewable sources. Incentives for nuclear projects are also provided.
Kenya	**Structure and ownership:** The reform encouraged private investments in the form of IPPs. The confidence of private investors was ensured by attractive PPAs with 'take or pay' clauses. The PPAs stimulated private investments in generating technologies with high operational costs such as oil fired plants. Since 2000, private investors began to build renewable power plants, especially geothermal and wind. This is mainly motivated by regulatory incentives such as CO_2 credits and FITs. **Network pricing:** Transmission prices are determined by power plant's distance from the main grid. This tends to discourage investments in renewable capacities. **Special incentives:** Several measures have been used by the government to encourage investments in renewable power plants.

TABLE 11. THE INFLUENCE OF NON-REFORM RELATED FACTORS ON THE TECHNOLOGY MIX IN TRANSITION AND POTENTIAL MARKETS

China	**Climate change and energy security:** Energy security and climate change concerns have encouraged the development of a diversified technology mix, including nuclear, coal, natural gas, hydropower and renewables. **Demand growth:** China is rapidly industrializing and urbanizing. This triggers fast increasing demand for energy, especially electricity. **Fukushima accident:** In response to the Fukushima accident, measures were taken by the government to conduct safety inspections of all nuclear facilities.
India	**Climate change and energy security:** Energy security and climate change concerns have prompted the development of a diversified technology mix comprising nuclear energy, hydropower and renewables. **Demand growth:** Keeping up with the fast economic growth (GDP growth above 8%/year), electricity demand is also increasing significantly. **Fukushima accident:** The accident has polarized the public opinion about nuclear power. The government supports the development of nuclear energy in the country while public opposition to NPPs emerged as a potential threat to the planned capacity expansion.
Indonesia	**Size of customers:** The size of customers affects the choice of power generation technologies. Small customers tended to rely on diesel engines and mini or micro hydropower plants. **Geography and demography:** The structure of electricity consumers is quite different across the islands. This affects investors' choice of generating technologies. Diesel generators are normally operated in very small islands while diverse sources of power generation (such as coal, hydro, natural gas and geothermal) are used in big islands. **Fuel price:** Oil was sold to households at subsidized prices until 2006. Industrial consumers had to pay higher prices. This encouraged many industrial consumers to build diesel power plants for their own use. When oil prices increased and the government reduced the subsidies, many industrial consumers stopped using their own diesel plants. **Climate change:** As a response to climate change concerns, the government promotes the use of renewable energy and emphasizes improvements in the efficiency of power generation. **Fukushima accident:** Since the Fukushima accident, opponents of nuclear power have increased their protests. This makes the task of developing nuclear energy more difficult for the government.
Malaysia	**Fukushima accident:** The accident has shifted the public against nuclear power. The government realizes that it has to do more to convince the public about the need for nuclear energy. This is likely to delay the implementation of the first nuclear power project.
Philippines	**Energy endowment:** The country is not endowed with extensive energy resources and has to import most of its fuel needs for electricity generation. Some regions have large geothermal potentials that encourage investors to exploit them. **Political factors:** Political factors have a significant influence on the institutional arrangements in the power sector. This affects the investors' decisions about generating technologies. **Fukushima accident:** Even after the recent accident in Japan, the government leaves the nuclear option open, although there has been opposition from environmentalists and other social organizations in the past few years.

TABLE 11. THE INFLUENCE OF NON-REFORM RELATED FACTORS ON THE TECHNOLOGY MIX IN TRANSITION AND POTENTIAL MARKETS (cont.)

Thailand	**Climate change:** Renewable energy is an attractive option for reducing the use of natural gas and oil in power production. It will allow the government to meet its policy goals of diversifying energy supply, reducing GHG emissions and promoting clean energy in accordance with the Renewable Energy Development Plan. **Energy security:** Energy security concerns have moved to the forefront of the country's energy policy debate. The government intends substitute oil and gas with other energy resources (such as coal) to enhance energy security. **Energy efficiency:** With the aim of promoting efficient energy utilization and electricity production, the government has provided incentives to promote the use of cogeneration systems that are capable of producing electricity and steam. **Demand growth:** In order to meet the growing demand for electricity, significant generating capacities will be required. Despite increased additions of renewable energy and cogeneration, the industry will still have insufficient capacity. Nuclear power therefore becomes an attractive option for the country. **Fukushima accident:** The accident has raised concerns about nuclear power.
Pakistan	**Energy endowment:** The government intends to promote electricity generation from indigenous resources including hydro, coal and renewables. **Demand growth:** It is anticipated that around 35 000 MW of new capacity will be needed by 2023 to meet future electricity demand. This capacity expansion is expected to be met primarily by the exploitation of indigenous resources including hydro, coal and renewables. **Fukushima accident:** The government is committed to operate the existing and to build more NPPs in the future. The PAEC started an extensive programme to revisit the safety plans of operating plants and has taken measures to ensure safety in the design and operation of NPPs.
South Africa	**Energy endowment:** South Africa has copious coal reserves, thus he power sector is dominated by coal fired power plants. **Climate change and energy security:** Energy security and climate change concerns are driving the generation technology mix away from coal towards nuclear and renewables. **Rural electrification:** Rural electrification and off-grid power promotes the use of solar panels, solar water heaters and small wind turbines. **Fukushima accident:** The government has stated its commitment to ensuring that future nuclear projects in the country take full account of the lessons learned from this accident.
Turkey	**Energy efficiency:** The government is well aware of the need to reduce the country's energy import dependence by improving energy efficiency, among other measures. **Demand growth:** It is projected that electricity demand will increase at 7%/year in the coming years. This rapid demand growth will require timely new investments in generation capacities. **Fukushima accident:** The accident has had no impact on the government's plan to advance nuclear projects.
Kenya	**Energy endowment:** Kenya has abundant geothermal resources. The government has implemented several measures to harness this resource for power generation. **Climate change:** Power generation from renewable sources especially geothermal and wind has been promoted with the aim of reducing the growth rate of GHG emissions. Some of these projects were supported by the CDMs under the Kyoto Protocol. **Demand growth:** Demand for electricity has been increasing at a faster rate than economic growth. High projections of electricity demand have provided incentives to invest in geothermal plants. In the future, electricity may be needed from resources that have not been previously utilized in Kenya such as coal, natural gas and nuclear power. **Fukushima accident:** The accident has divided experts about the suitability of nuclear power for the country.

5. THE IMPACTS OF ELECTRICITY MARKET REFORMS: SOME FURTHER ANALYSIS

This section analyses the wider implications of the electricity market reforms in selected countries. The impact areas include trends in electricity prices for households (Table 12) and for industry (Table 13), as well as changes in the generation capacity mix (Table 14) and in the contribution of different technologies to the total electricity output (Table 15). Public and private sector capacity additions and trends in private investments are also discussed. The key messages are summarized below.

5.1. ELECTRICITY PRICES

There is a declining trend in average electricity prices for households and industrial consumers in almost all countries included in this report over the period 1980–2002 (see Tables 12 and 13). Electricity prices in New Zealand and in the UK decreased most appreciably. In New Zealand, electricity prices for industry decreased from 10.3 US cent/kW·h in 1980 to 3.5 US cent/kW·h in 2002. The corresponding figures for the UK are 18 US cent/kW·h in 1980 and 5.7 US cent/kW·h in 2002. Proponents of the reforms attribute this decline to the reform programmes. However, this is an erroneous claim. The declining price trends were already in place much before the onset of the reforms in the early- to mid-1990s. These early trends were largely due to internal reforms undertaken in the sector in various countries and not the market reforms of the 1990s.

After 2003, electricity prices began to increase for households and industrial consumers in almost all case study countries included in this report (see Tables 12 and 13). The increasing trend in electricity prices is more apparent in countries with mature markets. For example, in the UK, electricity prices for industry increased from 5.8 US cents/kW·h in 2003 to 11.9 US cents/kW·h in 2013.

In the 2000s, industrial electricity prices have tended to increase at a relatively slower pace as compared with the rise in household prices (see Tables 12 and 13). This provides credence to the often heard argument that power sector reforms have been biased in favour of large industrial consumers that have been able to secure low electricity prices either through their early exposure to the generally low wholesale spot prices (in regimes of excess capacity) or long term contracts with generators fixing prices at a low level.

In some *transition and potential markets*, average electricity prices for industrial consumers have continued to decline, probably because these markets have not yet matured and various forms of subsidies may have persisted (see Table 13).

5.2. CHANGES IN THE TECHNOLOGY MIX

Over the period 1980–2011, the overall share of thermal capacities (coal, oil and natural gas) decreased from 78% in 1980 to 72% in 2011 in the aggregated group of all countries (see Table 14). This suggests a modest decline in the relative importance of TPPs in restructured electricity markets.

Thermal capacities have traditionally been the mainstay of the electricity industry in the *mature markets* group. The share of thermal capacities in this group declined from 79% to 71% over the 1980–2011 period (see Table 14). The decline in the share of thermal capacities has been particularly evident in several countries in this group such as the UK and Germany.

In the UK, the share of thermal capacities decreased from 88% in 1980 to 73% in 2012. The corresponding figures for Germany are 79% in 1980 and 49% in 2012.

In contrast, shares of thermal capacities have slightly increased in *transition and potential markets,* from 70% in 1980 to 72% in 2011 (see Table 14). In China, India, Indonesia, Malaysia, Thailand and South Africa, the share of thermal capacities in 2011 was more than 70%. Coal was the dominant fuel, accounting for overwhelmingly large shares in China, India, Indonesia and South Africa, while natural gas was the dominant fuel for power production in Malaysia and Thailand.

There has been a noticeable increase in the role of natural gas technologies in many countries (e.g. Australia, UK, USA and Turkey). The shares of natural gas-based generation capacities increased most noticeably in the UK (from 6% in 1980 to 42% in 2012) and in Turkey (from zero in 1980 to 35% in 2012).

Hydroelectricity has traditionally played an important role in terms of both capacity and generation shares in New Zealand, Chile, Colombia, Pakistan, Turkey and Kenya. However, the shares of hydro capacity in these and other countries have declined over the 1990–2011 period. Parallel to the decline of hydropower shares in total installed capacities, the shares of hydropower contribution to the total electricity output has also declined.

In *mature markets*, there has been a noticeable increase in the share of nuclear capacities over the period 1980–1990 (from 8 to 13%). This share declined to 9% by 2011, driven by prevalent concerns about nuclear safety (see Table 14). In contrast, the share of nuclear generation has continued to increase over the same period from 10% in 1980 to 17% in 2011, that indicates improved capacity factors and the increased use of nuclear power for baseload and middle-load electricity generation (Table 15).

The role of renewable technologies has been expanding in all countries. There is an obvious disconnection between the capacity and generation shares of renewable technologies in *transition and potential markets*. Their capacity share increased from 1 to 4% over the period 1980–2010 (see Table 14) but the corresponding generation share remained stagnant at 2% (see Table 15). This is due to the intermittent availability of renewable sources and the resulting low capacity factors as well as their relative cost disadvantages.

5.3. PUBLIC AND PRIVATE PARTICIPATION

In *transition and potential markets*, the contribution of public sector to capacity additions remained far above that of the private sector in the case study countries over the period 1990–2011. Also in *transition and potential markets*, while the private sector involvement was relative low in general, there was a slight upswing in private participation in the period 1995–1999. In the period 1990–1994, the private sector contributed only around 2 GW of the 126 GW total added capacity. In the 1995–1999 period, it contributed marginally more, 14 GW of the 353 GW total new capacity additions [92]. This is largely attributable to the efforts of governments, especially in China, Indonesia and the Philippines, to allow private participation in order to alleviate crippling power shortages. However, even this rather modest increase in private participation in these countries declined considerably in the period 2008–2011, when only 17 GW of capacity was added by the private sector while the public sector contributed about 448 GW of the total 465 GW capacity additions in this period.

In *transition and potential markets*, thermal capacity accounted for nearly 74% (1092 GW), followed by hydropower capacity (18%, 269 GW) of the 1481 GW total capacity added in the period 1990–2011. The public sector showed more interest in adding hydropower capacity (264 GW) than the private sector (5 GW). Renewable capacities steadily increased, especially in 2000–2011 [92].

Nuclear capacity remained in the domain of the public sector *transition and potential markets*. The entire newly added capacity in these countries over the period 1990–2011 was contributed by the public sector.

5.4. PRIVATE INVESTMENT TRENDS

Over the period 1990–2013, approximately $133 billion of private capital was invested in the electric power sector in the *transition and potential markets*, mostly in generation (90%) but also in transmission (4%) and distribution (6%) [92].

The pace of private investments varied considerably over the 1990–2010 period in these markets. Of the $133 billion of private investment, around $15 billion was made between 1990 and 1994, $51 billion in the period 1995–1999, $36 billion in 2000–2007 and $29 billion over the period 2008–2013 [92].

Over the period 1990–2013, the timing of private investment activities varied across the case study countries. In Chile, Colombia, China, Indonesia and the Philippines, private investments were appreciably high in the mid-1990s, whereas there was a rapid surge in private investments in the mid- to late 2000s in India, with unprecedented high investments (approximately $16 billion) between 2005 and 2013.

In the generation segment, the investment trends have varied across generation technologies. Investments in coal-based technologies were most significant in China, India and Indonesia, natural gas technologies dominated in Thailand and Turkey, while natural gas and hydropower were the main technologies in Chile.

TABLE 12. ELECTRICITY PRICES FOR HOUSEHOLDS (US CENTS/kW·h, AT 2005 PRICES)

		1980	1990	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Mature markets	Australia	13.7	10.4	7.3	7.0	7.2	8.7	10.1	11.2	11.8	12.9	13.9	11.8	14.6	16.3	18.7	20.8
	New Zealand	12.4	7.4	6.8	6.5	7.6	10.0	12.4	13.6	12.9	15.3	14.9	13.5	15.8	16.6	17.3	17.9
	UK	25.0	18.0	12.0	11.1	11.5	12.3	14.2	14.9	18.0	20.3	20.7	18.5	17.1	18.3	19.4	20.8
	Germany	17.8	22.4	13.0	13.1	14.1	18.1	20.1	21.2	21.8	25.3	30.3	29.7	29.5	31.7	32.5	36.4
	Lithuania	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Poland	-	12.9	7.5	8.6	8.9	10.0	10.5	12.1	13.1	14.6	17.9	14.9	15.5	16.6	17.6	17.6
	USA	12.7	11.7	9.3	9.4	9.2	9.2	9.3	9.4	10.1	10.0	10.2	10.5	10.4	10.6	10.6	10.8
	Chile	-	11.5	9.7	9.0	8.5	8.7	10.0	12.0	13.2	15.3	19.5	18.1	17.5	16.2	13.9	12.9
	Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transition and potential markets	China	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	India[a]	-	-	-	-	-	5.3	-	7.0	7.8	8.8	7.1	7.4	7.6			
	Indonesia	-	36.2	3.8	3.5	5.3	7.1	6.9	5.8	5.5	5.2	4.6	4.1	4.6	-	-	-
	Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Philippines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	South Africa	65.0	16.9	5.1	4.3	3.5	5.1	6.2	6.1	5.7	-	-	-	-	-	-	-
	Thailand	15.9	10.9	6.7	6.6	6.9	6.9	7.3	7.2	8.1	8.5	8.3	8.8	9.2	-	-	-
	Turkey	-	-	28.7	18.6	15.1	12.9	12.2	11.8	10.0	10.2	12.4	11.7	12.0	12.3	14.8	16.3
	Kenya	-	-	14.9	-	-	11.2	8.1	9.0	9.9	9.7	7.7	9.4	9.4	-	-	-

[a] Actual Tariff in Delhi for monthly domestic consumption of 400 kW·h.
Sources: [93] and participating country reports.

TABLE 13. ELECTRICITY PRICES FOR INDUSTRY (US CENTS/kW·h, AT 2005 PRICES)

		1980	1990	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Mature markets	Australia	9.7	6.6	5.2	4.9	5.3	5.7	6.3	7.0	7.3	8.0	8.6	7.3	8.9	9.8	11.2	12.8
	New Zealand	10.3	4.6	3.2	3.0	3.5	4.9	5.3	6.1	5.8	6.5	6.5	5.8	6.5	6.5	7.0	8.8
	UK	18.0	10.8	6.2	5.6	5.7	5.8	6.9	8.7	11.3	12.1	13.0	12.1	10.4	10.7	11.3	11.9
	Germany	10.2	12.5	4.4	4.6	5.1	6.8	7.8	8.4	9.3	10.5	12.1	13.0	12.6	13.3	13.4	14.8
	Lithuania	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Poland	-	31.6	4.2	4.9	5.2	5.9	6.1	7.0	7.2	7.9	11.0	10.7	10.5	9.7	9.7	9.1
	USA	8.7	7.1	5.2	5.5	5.2	5.4	5.4	5.7	6.0	6.0	6.2	6.2	6.1	6.4	6.6	6.4
	Chile	-	-	5.4	5.5	5.2	5.3	6.2	7.7	8.7	10.6	14.5	13.4	12.7	-	-	-
	Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transition and potential markets	China	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	India[a]	-	-	-	-	-	10.1	-	12.1	12.6	14.2	11.6	12.2	12.5	-	-	-
	Indonesia	-	26.8	5.6	4.9	5.9	7.3	6.9	5.9	6.0	5.6	4.9	4.5	5.0	-	-	-
	Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Philippines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pakistan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	South Africa	-	8.5	2.2	1.6	1.4	2.0	2.2	2.2	2.1	-	-	-	-	-	-	-
	Thailand	14.2	10.7	6.4	6.1	6.3	6.4	6.6	6.6	7.4	6.8	6.7	6.8	6.3	-	-	-
	Turkey[b]	-	-	27.3	17.5	14.3	12.1	11.0	10.6	9.0	9.1	10.5	9.8	9.9	10.2	11.2	-
	Kenya	-	31.4	14.0	-	-	9.8	8.7	9.4	9.9	9.7	7.7	9.4	9.7	-	-	-

[a] Actual tariff in Delhi for industry with more than 1000 kW load and monthly consumption of 438 MW·h.
Sources: [93] and participating country reports.

TABLE 14. GENERATION CAPACITY MIX[a]

	Year	Total (GW)	Thermal[b]		Hydro		Nuclear		Other renewables[c]	
			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
Mature markets	1980[d]	887	714	80	104	12	67	8	2	0
	1990	1030	743	72	131	13	139	13	18	2
	2000	1175	866	74	143	12	135	12	31	3
	2005	1314	984	75	145	11	133	10	52	4
	2006	1328	990	75	145	11	133	10	60	5
	2007	1346	997	74	146	11	132	10	71	5
	2008	1370	1007	73	146	11	133	10	85	6
	2009	1399	1014	72	147	11	133	9	105	7
	2010	1434	1032	72	148	10	132	9	122	9
	2011	1458	1039	71	150	10	123	8	146	10
	2012	1485	1033	70	150	10	123	8	180	12
	2013	1493	1022	68	151	10	121	8	200	13
	2014[d]	1789	1296	72	151	8	120	7	222	12
Transition and potential markets	1980	146	104	71	41	28	1	0	0	0
	1990	318	238	75	76	24	3	1	1	0
	2000	618	472	76	133	22	7	1	5	1
	2005	873	666	76	183	21	12	1	11	1
	2006	1001	770	77	203	20	13	1	15	1
	2007	1136	881	78	217	19	15	1	24	2
	2008	1236	941	76	247	20	15	1	34	3
	2009	1332	1002	75	272	20	15	1	44	3
	2010	1450	1078	74	293	20	17	1	63	4
	2011	1576	1157	73	314	20	19	1	87	6
	2012	1709	1242	73	334	20	20	1	113	7
	2013	1859	1323	71	371	20	22	1	143	8

[a] The base data for this table is provided in the Appendix Table I-1
[b] Thermal capacity s includes coal, oil and gas
[c] Other renewables include geothermal, wind, solar, biomass and waste
[d] Does not include the data on Lithuania

TABLE 14. GENERATION CAPACITY (cont.)[a]

	Year	Total (GW)	Thermal[b]		Hydro		Nuclear		Other renewables[c]	
			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
Total	1980[d]	1033	818	79	145	14	68	7	3	0
	1990	1348	981	73	206	15	142	11	19	1
	2000	1792	1338	75	276	15	142	8	36	2
	2005	2187	1650	75	328	15	145	7	63	3
	2006	2330	1760	76	348	15	146	6	75	3
	2007	2482	1878	76	363	15	146	6	95	4
	2008	2606	1948	75	393	15	147	6	119	5
	2009	2730	2016	74	419	15	147	5	148	5
	2010	2884	2110	73	441	15	148	5	185	6
	2011	3034	2195	72	464	15	142	5	233	8
	2012	3194	2275	71	484	15	143	4	293	9
	2013	3352	2345	70	521	16	143	4	343	10

[a] The base data for this table is provided in the Appendix Table I-1
[b] Thermal capacity s includes coal, oil and gas
[c] Other renewables include geothermal, wind, solar, biomass and waste
[d] Does not include the data on Lithuania

TABLE 15. ELECTRICITY PRODUCTION[a]

	Year	Total (TW·h)	Thermal[b]		Hydro		Nuclear		Other renewables[c]	
			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
Mature markets	1980[d]	3453	2718	79	362	10	359	10	14	0
	1990	4495	3137	70	394	9	847	19	117	3
	2000	5496	3900	71	410	7	1061	19	124	2
	2005	5861	4169	71	442	8	1066	18	185	3
	2006	5897	4154	70	468	8	1068	18	208	4
	2007	5961	4254	71	422	7	1050	18	235	4
	2008	5969	4226	71	426	7	1049	18	268	4
	2009	5738	3956	69	439	8	1045	18	297	5
	2010	5973	4167	70	426	7	1042	17	339	6
	2011	5922	4026	68	492	8	998	17	405	7
	2012	5877	4003	68	443	8	971	17	460	8
	2013	5891	3948	67	434	7	990	17	519	9
Transition and potential markets	1980	610	470	77	134	22	3	0	2	0
	1990	1306	1019	78	265	20	15	1	11	1
	2000	2638	2184	83	381	14	49	2	32	1
	2005	4124	3388	82	613	15	84	2	59	1
	2006	4598	3789	82	676	15	86	2	68	1
	2007	5112	4243	83	719	14	93	2	84	2
	2008	5342	4360	82	806	15	98	2	104	2
	2009	5689	4643	82	834	15	104	2	140	2
	2010	6282	5048	80	975	16	116	2	187	3
	2011	6923	5624	81	970	14	137	2	245	4
	2012	7293	5776	79	1136	16	148	2	290	4
	2013	7765	6095	78	1219	16	163	2	348	4

[a] The base data for this table is provided in the Appendix Table I-2
[b] Thermal capacity s includes coal, oil and gas
[c] Other renewables include geothermal, wind, solar, biomass and waste
[d] Does not include the data on Lithuania

TABLE 15. ELECTRICITY PRODUCTION (cont.)[a]

	Year	Total (TW·h)	Thermal[b]		Hydro		Nuclear		Other renewables[c]	
			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
Total	1980[d]	4063	3188	78	497	12	362	9	16	0
	1990	5801	4156	72	659	11	862	15	128	2
	2000	8133	6083	75	791	10	1109	14	157	2
	2005	9985	7557	76	1055	11	1150	12	243	2
	2006	10495	7942	76	1144	11	1154	11	276	3
	2007	11074	8497	77	1142	10	1144	10	319	3
	2008	11311	8586	76	1232	11	1147	10	373	3
	2009	11427	8599	75	1273	11	1150	10	438	4
	2010	12255	9215	75	1400	11	1157	9	526	4
	2011	12845	9650	75	1462	11	1136	9	650	5
	2012	13170	9779	74	1578	12	1119	8	750	6
	2013	13656	10043	74	1653	12	1153	8	867	6

[a] The base data for this table is provided in the Appendix Table I-2
[b] Thermal capacity s includes coal, oil and gas
[c] Other renewables include geothermal, wind, solar, biomass and waste
[d] Does not include the data on Lithuania

6. CONCLUSIONS

The electricity industries around the world have been in the throes of change for the last two decades or so. While the pace of change has differed across the countries, the nature of change is quintessentially the same, namely, a structural separation of generation, transmission, distribution and retail segments of the vertically integrated utilities; introduction of competition in generation and retail; development of non-discriminatory access arrangements for transmission and distribution; replacement of centralized state-directed regulatory arrangements with market-based arrangements; and privatization. These changes were premised on the assumption that they will result in a leaner and fitter electricity industry, able to respond to community needs and expectations (for example, for affordable, adequate and reliable electricity) and challenges (for example, climate change, air pollution mitigation) through the selection of efficient technologies and operating practices.

This report analyses the impacts of electricity market reforms and non-reform factors on the selection of technologies for the generation mix, including nuclear power. The main findings of the analysis are summarized in this section.

The analysis covers 19 countries divided into mature, transition and potential markets. Preliminary assessments indicated a considerable degree of similarity in the outcomes for transition and potential markets; therefore the results for these two groups are reported jointly in order to avoid unnecessary repetitions. Key findings of the analysis are summarized in Tables 16 and 17.

TABLE 16. RATIONALE FOR REFORMS: MAJOR DRIVERS

Markets	Major drivers
Mature markets	Economy-wide reform programmes driven by factors such as the globalization of the world economy and pressures to improve domestic and international competitiveness of national economies, the trends towards smaller government and emerging beliefs in free market principles. Economic crises of the 1980s. More recently, growing concerns about climate change and energy security.
Transition and potential markets	Needs to attract new investments (especially foreign) to meet rising electricity demand. Actively advocated by multilateral financial organizations (e.g. the World Bank).
All countries	A rather diverse and sweeping range of objectives for reforming the electricity industries. No compelling logic behind various objectives. Strongly motivated by ideological considerations.

TABLE 17. REFORM CHARACTERISTICS IN MATURE AND IN TRANSITION AND POTENTIAL MARKETS

Characteristics	Mature markets	Transition and potential markets
Structure and ownership	Growing tendency for vertical integration between generators and retailers. Mixed public/private ownership except in some countries (such as Chile, UK and USA) and some states of Australia where private ownership dominates the power sector.	Some variation of the single buyer model. Private involvement is still limited and mainly confined to the generation segment of the industry.
Regulatory frameworks	High degree of regulatory independence where the responsibility of the regulator is largely confined to monitoring and compliance, licensing and regulation of the general market (i.e. to prevent the abuse of market power) and networks (i.e. to ensure non-discriminatory access to monopoly networks), and to network access pricing. Electricity prices for small consumers are still subject to some form of regulation (typically price caps). Special regulatory incentives for supporting the uptake of renewable energy.	Governments continue to have a significant role in the regulation of the industry including licensing and the setting of electricity tariffs for generation, line businesses and end-users. Electricity tariffs are generally determined by the 'cost of service' principle. Special regulatory incentives for supporting the uptake of renewable energy.
Market mechanisms	Market-based pricing is the norm. The market is generally organized in the form of a pool market or a power exchange. Customer choice has been extended to most customers but such choice has sometimes been confined to large customers.	Formal market mechanisms have not yet been established and power continues to be sold through some variation of the single buyer model.
Risk allocation	Electricity industry reform has gradually shifted investment risks from the consumers to the investors. A range of measures has been developed for investors to manage the risks, including the establishment of formal financial markets, provision of bilateral contracts through the OTC market and reintegration between generators and retailers.	Investment risks are allocated to the consumers. The IPPs supply electricity under PPAs that allows them to pass through their risks to the single buyer. The single buyer delivers electricity to the end users under regulated prices that are determined according to 'cost of service' principle.

In addition to the general characteristics summarized in Table 17, the national case studies show a diverse picture even within the same country groups (mature markets and transition and potential markets) in terms of industrial structure, especially the degree of vertical integration, and ownership, i.e. the extent of private ownership in power generation companies. The nature, depth and rigour of regulation and the ensuing role of market forces also varies significantly across mature markets while regulation is heavier and market mechanisms are weaker or missing altogether in transition and potential markets. The key question is how the resulting combination affects the risks investor need to take because this is a crucial factor affecting the choice of generation technologies.

The case studies indicate that both the measures to reform electricity markets and many non-reform related factors shape the power sector, albeit their relative importance diverges across countries to a large extent. The most profound implication of the reforms, especially in mature markets, is that electricity prices are no longer set by the ‘rate of return’ or similar principles but are shaped by market mechanisms. As a result, the financial risks associated with investments become visible to investors. Of the non-reform factors, climate change has become an important driver in mature markets because the extensive and guaranteed support for renewable technologies reintroduces guaranteed prices or revenues that the market reforms were trying to abolish.

The restructuring, privatization and reregulation to establish mature markets have triggered generation companies to implement risk mitigation measures such as establishing formal financial markets, bilateral contracts through OTC markets, long term contract auctions and even attempts to reintegrate generators and retailers. Yet the incentive to reshape the investment portfolios away from large scale, capital intensive technologies towards those involving shorter construction times and lower investment volumes and risks remains strong, further supported by non-reform related factors such as slow growth in electricity demand and policies to support low carbon technologies, especially wind and solar energy.

Reforms have progressed modestly in transition and potential markets and did not considerably affect the risks faced by investors. Although there are some competitive elements in awarding them in some countries, PPAs are still dominated by the ‘cost of service’ principle and allow investors to pass practically all risks to the single buyer, thus indirectly to the consumer or tax payer. The special incentives supporting investments in renewable technologies foster the diversification of the generation technology mix in countries with transition or potential electricity markets, too.

It follows that nuclear energy, involving large investments, long construction times and the associated financial risks, is not the preferred technology in mature markets despite its possibly competitive generation costs and favourable environmental performance (low emissions of GHGs and other air pollutants). However, broader policy considerations, such as energy supply security, stability and reliability of the power grid, climate change concerns) can justify special regulatory arrangements under with private investors might be enticed to invest in nuclear energy projects.

The prospects for nuclear power are more favourable in transition and potential markets. PPAs are easier to arrange under the prevailing regulatory conditions and they reduce the associated risks for investors significantly. Some non-reform factors foster the case of nuclear energy in these countries as well. They include fast increasing demand for electricity, strong concerns over supply security and increasing interest in climate change mitigation. Accordingly, among the countries involved in this study, all countries in the transition and potential markets group operate or plan/consider to introduce nuclear power while only about half of the countries in the mature market group do so.

In summary, other things being equal, attributes of nuclear power investments (large investment costs and long construction period) are less attractive to private investors in mature and fully liberalized electricity markets that value rapid returns than to a government that can consider longer term economic returns and public benefits. This is particularly valid under regulated or transition market conditions that guarantee attractive returns. Private investment in nuclear power under liberalized market conditions will also depend on the extent to which energy related external costs and benefits are internalized and reflected in electricity prices. In contrast, institutional (especially publicly owned) investors can incorporate such externalities directly into their decisions. All these factors, together with regulatory risks, political support and public acceptance, influence the prospects for nuclear power.

APPENDIX I. POWER SECTOR DATA FOR PARTIPATING COUNTRIES

This appendix presents power generation capacity and electricity production data for the case study countries included in this report. They are intended to support further exploration of the evolution of the power sector in individual countries by interested readers.

TABLE I-1. GENERATION CAPACITY

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Mature markets														
Australia	1980	25.7	14.5	2.8	2.1	56	11	8	6.1	24	0.0	0	0.2	1
	1990	38.4	24.5	1.6	3.8	64	4	10	8.3	22	0.0	0	0.2	1
	2000	46.2	26.7	3.9	6.0	58	8	13	9.2	20	0.0	0	0.4	1
	2005	50.1	29.0	2.0	9.0	58	4	18	8.5	17	0.0	0	1.7	3
	2006	50.7	28.8	2.0	9.5	57	4	19	8.5	17	0.0	0	1.8	4
	2007	53.4	28.9	1.9	11.8	54	4	22	8.6	16	0.0	0	2.2	4
	2008	54.3	29.3	2.0	12.3	54	4	23	8.6	16	0.0	0	2.3	4
	2009	57.1	29.7	2.0	14.4	52	3	25	8.6	15	0.0	0	2.3	4
	2010	59.9	30.0	2.1	16.4	50	3	27	8.8	15	0.0	0	2.6	4
	2011	61.9	30.2	2.2	16.9	49	4	27	8.8	14	0.0	0	3.8	6
	2012	64.1	30.3	2.1	17.5	47	3	27	8.8	14	0.0	0	5.4	8
	2013	65.4	29.4	2.1	17.6	45	3	27	9.2	14	0.0	0	7.0	11
	2014	67.5	29.4	2.1	18.3	44	3	27	9.2	14	0.0	0	8.5	13
New Zealand	1980	6.0	0.5	0.2	0.8	8	4	13	4.3	71	0.0	0	0.3	4
	1990	7.4	0.9	0.2	1.1	12	3	15	4.8	65	0.0	0	0.4	5
	2000	8.0	0.8	0.0	1.5	10	0	18	5.2	65	0.0	0	0.5	6
	2005	8.9	0.7	0.2	1.8	8	2	21	5.3	60	0.0	0	0.9	10
	2006	8.9	0.7	0.2	1.8	8	2	21	5.3	60	0.0	0	0.9	10
	2007	9.4	0.7	0.2	2.2	7	2	24	5.3	57	0.0	0	1.0	11
	2008	9.4	0.6	0.2	2.1	6	2	23	5.4	57	0.0	0	1.2	13
	2009	9.4	0.5	0.2	2.0	5	2	22	5.3	57	0.0	0	1.4	15
	2010	9.7	0.5	0.2	2.2	5	2	23	5.3	54	0.0	0	1.5	16
	2011	9.8	0.5	0.2	2.2	5	2	23	5.3	54	0.0	0	1.6	16
	2012	9.6	0.4	0.2	2.2	4	2	23	5.3	55	0.0	0	1.6	17
	2013	9.6	0.3	0.2	2.1	3	2	22	5.3	55	0.0	0	1.9	19
	2014	9.6	0.3	0.2	2.1	3	2	22	5.3	55	0.0	0	1.9	19

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
United Kingdom	1980	73.6	42.8	20.3	1.6	58	28	2	2.5	38	6.4	3	0.0	9
	1990	73.3	40.6	15.8	1.1	55	22	2	4.2	29	11.4	6	0.1	16
	2000	78.4	33.0	5.2	22.2	42	7	28	4.3	8	12.5	5	1.2	16
	2005	82.3	30.2	5.4	27.4	37	7	33	4.2	8	11.9	5	3.2	14
	2006	83.5	30.9	6.0	27.8	37	7	33	4.1	9	11.0	5	3.7	13
	2007	83.4	31.6	6.0	27.2	38	7	33	4.2	9	10.2	5	4.2	12
	2008	84.8	30.2	6.0	29.0	36	7	34	4.3	8	10.1	5	5.2	12
	2009	86.7	30.2	6.1	29.5	35	7	34	4.3	8	10.1	5	6.4	12
	2010	92.9	30.3	6.2	34.2	33	7	37	4.3	7	10.1	5	7.7	11
	2011	92.3	28.6	5.7	32.8	31	6	36	4.3	7	9.9	5	10.9	11
	2012	94.0	26.5	4.2	35.6	28	4	38	4.3	5	9.2	5	14.1	10
	2013	92.2	21.8	3.3	35.4	24	4	38	4.3	4	9.2	5	18.2	10
	2014	95.5	21.5	3.3	35.4	22	3	37	4.3	4	9.4	4	21.7	10
Germany	1980	108.1	64.0	14.8	11.4	59	14	11	8.5	13	8.6	8	0.8	8
	1990	122.0	66.8	10.7	11.6	55	9	9	9.5	7	22.4	8	1.0	18
	2000	122.1	54.1	7.5	21.2	44	6	17	9.6	5	22.4	8	7.4	18
	2005	131.0	51.4	5.5	19.5	39	4	15	10.9	3	20.4	8	23.4	16
	2006	134.7	50.5	5.5	20.1	37	4	15	10.8	3	20.2	8	27.6	15
	2007	139.1	51.8	5.4	20.0	37	4	14	10.8	3	20.2	8	30.9	15
	2008	144.5	52.0	5.4	21.6	36	4	15	10.8	3	20.5	7	34.3	14
	2009	151.6	51.5	5.2	21.6	34	3	14	11.2	2	20.5	7	41.7	14
	2010	163.7	52.8	5.9	22.0	32	4	13	11.2	2	20.5	7	51.3	12
	2011	168.6	55.1	6.4	22.3	33	4	13	11.4	2	12.1	7	61.3	7
	2012	178.1	54.0	4.2	24.8	30	2	14	11.3	1	12.1	6	71.8	7
	2013	182.2	52.3	2.9	25.0	29	2	14	11.2	1	12.1	6	78.8	7
	2014	192.7	56.9	2.9	22.7	30	2	12	11.1	1	12.1	6	87.0	6

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Lithuania	1980	n.a.	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	n.a.
	1990	6.6	0.0	0.5	2.8	0	8	43	0.5	7	2.7	41	0.0	0
	2000	6.1	0.0	1.2	1.7	0	19	28	0.9	14	2.4	39	0.0	0
	2005	5.0	0.0	0.8	2.1	0	16	43	0.9	18	1.2	24	0.0	0
	2006	5.0	0.0	0.8	2.1	0	16	42	0.9	17	1.2	24	0.0	1
	2007	5.0	0.0	0.8	2.1	0	16	42	0.9	17	1.2	23	0.1	1
	2008	5.1	0.0	0.8	2.1	0	16	42	0.9	17	1.2	23	0.1	2
	2009	5.1	0.0	0.8	2.1	0	16	42	0.9	17	1.2	23	0.1	2
	2010	3.7	0.0	0.8	1.8	0	22	49	0.9	24	0.0	0	0.2	5
	2011	3.8	0.0	0.9	1.8	0	23	48	0.9	23	0.0	0	0.2	6
	2012	4.3	0.0	0.9	2.3	0	20	53	0.9	20	0.0	0	0.3	7
	2013	4.5	0.0	0.9	2.3	0	20	51	0.9	20	0.0	0	0.4	9
	2014	n.a.	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.3	n.a.
Poland	1980	27.7	24.8	1.6	0.0	90	6	0	1.3	5	0.0	0	0.0	0
	1990	29.7	27.4	0.4	0.0	92	1	0	1.9	6	0.0	0	0.0	0
	2000	32.3	29.2	0.3	0.5	90	1	2	2.2	7	0.0	0	0.0	0
	2005	32.9	29.2	0.5	0.8	89	1	2	2.3	7	0.0	0	0.1	0
	2006	33.1	29.3	0.5	0.8	88	1	3	2.3	7	0.0	0	0.2	1
	2007	33.4	29.4	0.5	0.8	88	1	2	2.3	7	0.0	0	0.4	1
	2008	33.6	29.5	0.5	0.8	88	1	2	2.3	7	0.0	0	0.5	2
	2009	34.0	29.5	0.5	0.8	87	1	2	2.3	7	0.0	0	0.8	2
	2010	34.3	29.1	0.5	1.0	85	1	3	2.3	7	0.0	0	1.3	4
	2011	35.5	29.8	0.4	1.0	84	1	3	2.3	7	0.0	0	1.9	5
	2012	36.7	29.8	0.4	1.0	81	1	3	2.4	6	0.0	0	3.1	8
	2013	37.1	29.2	0.4	1.0	79	1	3	2.4	6	0.0	0	4.1	11
	2014	36.9	28.3	0.4	1.1	77	1	3	2.5	7	0.0	0	4.6	12

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
United States	1980	638.2	245.7	105.2	157.3	39	16	25	76.7	12	52.3	8	1.0	0
	1990	739.4	270.7	82.4	176.1	37	11	24	92.4	12	102.1	14	15.9	2
	2000	858.9	321.1	129.9	190.1	37	15	22	98.9	12	97.9	11	21.1	2
	2005	978.1	315.4	58.5	383.1	32	6	39	98.9	10	100.0	10	22.1	2
	2006	986.4	315.2	58.1	388.3	32	6	39	99.3	10	100.3	10	25.2	3
	2007	995.3	315.1	56.1	392.9	32	6	39	99.8	10	100.3	10	31.2	3
	2008	1010.9	315.3	57.4	397.5	31	6	39	99.8	10	100.8	10	40.1	4
	2009	1026.5	316.2	56.8	401.3	31	6	39	100.7	10	101.0	10	50.6	5
	2010	1040.2	319.0	55.6	407.0	31	5	39	101.0	10	101.2	10	56.4	5
	2011	1053.7	319.9	51.7	415.2	30	5	39	100.9	10	101.4	10	64.5	6
	2012	1065.0	311.5	46.9	422.4	29	4	40	101.1	9	101.4	10	81.8	8
	2013	1068.0	307.7	45.6	426.9	29	4	40	101.3	9	99.2	9	87.3	8
	2014	1351.4	577.3	44.8	433.7	43	3	32	101.4	8	98.6	7	95.6	7
Chile	1980	2.9	0.6	0.8	0.0	20	29	0	1.5	50	0.0	0	0.0	1
	1990	4.7	1.2	0.9	0.1	25	19	2	2.3	50	0.0	0	0.2	4
	2000	10.2	2.2	0.8	2.7	22	8	27	4.1	40	0.0	0	0.3	3
	2005	12.5	2.1	1.0	3.9	17	8	31	4.8	39	0.0	0	0.6	5
	2006	12.8	2.1	1.1	3.9	16	9	30	4.9	38	0.0	0	0.8	6
	2007	13.5	2.1	1.7	3.9	15	13	29	5.0	37	0.0	0	0.8	6
	2008	14.2	2.1	1.8	4.3	15	13	30	5.0	35	0.0	0	0.9	7
	2009	15.0	2.1	2.5	4.3	14	16	29	5.1	34	0.0	0	1.1	7
	2010	16.4	2.4	3.1	4.3	15	19	26	5.5	33	0.0	0	1.2	7
	2011	17.8	3.2	3.1	4.3	18	17	24	6.0	34	0.0	0	1.2	7
	2012	19.0	3.8	3.1	4.5	20	16	24	6.0	32	0.0	0	1.6	8
	2013	19.1	4.1	3.0	4.1	22	15	21	6.1	32	0.0	0	1.8	10
	2014	20.2	4.2	3.0	4.1	21	15	20	6.5	32	0.0	0	2.5	12

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Colombia	1980	4.8	0.3	0.1	1.3	5	2	28	3.1	64	0.0	0	0.1	1
	1990	9.0	0.5	0.1	1.5	6	1	17	6.7	75	0.0	0	0.1	1
	2000	12.6	0.7	0.0	3.5	6	0	27	8.3	66	0.0	0	0.1	1
	2005	13.3	0.7	0.0	3.6	5	0	27	8.9	67	0.0	0	0.1	1
	2006	13.3	0.7	0.0	3.5	5	0	26	9.0	67	0.0	0	0.1	1
	2007	13.4	0.7	0.0	3.6	5	0	27	9.0	67	0.0	0	0.1	1
	2008	13.5	0.7	0.0	3.6	5	0	27	9.0	67	0.0	0	0.1	1
	2009	13.5	0.7	0.1	3.6	5	0	27	9.0	67	0.0	0	0.1	1
	2010	13.6	0.7	0.1	3.7	5	0	27	9.0	67	0.0	0	0.1	1
	2011	14.5	0.7	0.1	3.5	5	0	24	9.8	67	0.0	0	0.5	3
	2012	14.5	1.0	0.2	3.0	7	1	21	9.8	68	0.0	0	0.5	3
	2013	14.6	1.0	0.2	3.0	7	1	21	9.9	68	0.0	0	0.5	3
	2014	15.5	1.0	0.2	3.0	6	1	19	10.9	70	0.0	0	0.5	3
Transition and potential markets														
China	1980	69.7	29.9	18.0	1.5	43	26	2	20.3	29	0.0	0	0.0	0
	1990	149.1	92.3	18.0	2.7	62	12	2	36.0	24	0.0	0	0.0	0
	2000	336.1	225.4	20.1	8.2	67	6	2	79.4	24	2.2	1	0.9	0
	2005	530.6	370.1	25.0	10.0	70	5	2	116.5	22	6.6	1	2.4	0
	2006	645.2	462.4	25.0	14.0	72	4	2	132.2	20	7.5	1	4.1	1
	2007	758.2	551.9	20.0	24.5	73	3	3	145.3	19	8.5	1	8.0	1
	2008	840.3	594.9	20.0	29.0	71	2	3	172.6	21	8.5	1	15.3	2
	2009	917.8	645.9	15.0	30.0	70	2	3	196.3	21	8.5	1	22.1	2
	2010	1012.0	700.7	15.0	31.2	69	1	3	216.1	21	10.1	1	39.0	4
	2011	1107.8	751.7	15.0	37.2	68	1	3	233.0	21	11.7	1	59.3	5
	2012	1195.1	802.4	15.0	37.2	67	1	3	248.9	21	12.9	1	78.8	7
	2013	1297.7	847.1	15.0	39.2	65	1	3	280.0	22	15.0	1	101.4	8
	2014	1405.8	895.2	15.0	41.0	64	1	3	301.8	21	19.9	1	132.9	9

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
India	1980	73.6	42.8	20.3	1.6	58	28	2	2.5	3	6.4	9	0.0	0
	1990	73.3	40.6	15.8	1.1	55	22	2	4.2	6	11.4	16	0.1	0
	2000	78.4	33.0	5.2	22.2	42	7	28	4.3	5	12.5	16	1.2	2
	2005	82.3	30.2	5.4	27.4	37	7	33	4.2	5	11.9	14	3.2	4
	2006	83.5	30.9	6.0	27.8	37	7	33	4.1	5	11.0	13	3.7	4
	2007	83.4	31.6	6.0	27.2	38	7	33	4.2	5	10.2	12	4.2	5
	2008	84.8	30.2	6.0	29.0	36	7	34	4.3	5	10.1	12	5.2	6
	2009	86.7	30.2	6.1	29.5	35	7	34	4.3	5	10.1	12	6.4	7
	2010	92.9	30.3	6.2	34.2	33	7	37	4.3	5	10.1	11	7.7	8
	2011	92.3	28.6	5.7	32.8	31	6	36	4.3	5	9.9	11	10.9	12
	2012	94.0	26.5	4.2	35.6	28	4	38	4.3	5	9.2	10	14.1	15
	2013	92.2	21.8	3.3	35.4	24	4	38	4.3	5	9.2	10	18.2	20
	2014	95.5	21.5	3.3	35.4	22	3	37	4.3	4	9.4	10	21.7	23
Indonesia	1980	4.6	0.0	3.6	0.0	0	79	0	1.0	21	0.0	0	0.0	0
	1990	12.9	1.7	7.4	0.5	13	57	4	3.1	24	0.0	0	0.1	1
	2000	25.2	7.7	4.6	8.4	30	18	33	4.2	17	0.0	0	0.4	1
	2005	26.6	9.8	4.6	8.2	37	17	31	3.2	12	0.0	0	0.8	3
	2006	29.7	11.7	4.7	9.0	39	16	30	3.5	12	0.0	0	0.8	3
	2007	30.3	12.0	4.8	9.0	40	16	30	3.5	12	0.0	0	0.9	3
	2008	31.2	12.2	4.8	9.4	39	16	30	3.7	12	0.0	0	1.1	3
	2009	32.0	12.6	4.2	10.3	39	13	32	3.7	12	0.0	0	1.2	4
	2010	34.0	13.0	5.7	10.4	38	17	30	3.7	11	0.0	0	1.2	4
	2011	39.9	16.4	6.7	11.6	41	17	29	3.9	10	0.0	0	1.2	3
	2012	45.3	19.8	7.3	12.7	44	16	28	4.1	9	0.0	0	1.4	3
	2013	50.9	23.8	7.2	13.4	47	14	26	5.2	10	0.0	0	1.4	3
	2014	53.9	26.3	7.2	13.8	49	13	26	5.2	10	0.0	0	1.4	3

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Malaysia	1980	3.0	0.1	2.2	0.1	3	74	3	0.6	20	0.0	0	0.0	0
	1990	4.7	1.2	1.5	0.9	26	32	19	1.1	24	0.0	0	0.0	0
	2000	13.8	1.3	2.3	8.0	9	17	58	2.1	15	0.0	0	0.1	1
	2005	20.7	3.9	1.3	13.2	19	6	64	2.1	10	0.0	0	0.1	1
	2006	22.1	4.6	1.1	13.8	21	5	63	2.1	9	0.0	0	0.4	2
	2007	24.8	6.0	2.1	14.1	24	8	57	2.1	8	0.0	0	0.5	2
	2008	24.6	6.0	1.8	14.1	24	7	57	2.1	8	0.0	0	0.6	2
	2009	27.0	7.7	1.7	14.9	28	6	55	2.1	8	0.0	0	0.6	2
	2010	27.2	7.7	1.6	15.1	28	6	56	2.1	8	0.0	0	0.7	2
	2011	28.4	7.7	2.3	14.7	27	8	52	3.0	11	0.0	0	0.7	3
	2012	28.8	7.7	1.5	15.5	27	5	54	3.3	12	0.0	0	0.8	3
	2013	30.1	7.7	2.5	14.6	25	8	48	4.5	15	0.0	0	1.0	3
	2014	32.5	8.7	2.5	14.8	27	8	46	5.5	17	0.0	0	1.0	3
Philippines	1980	4.5	0.1	3.0	0.0	1	68	0	0.9	21	0.0	0	0.4	10
	1990	6.9	0.7	3.1	0.0	10	45	0	2.2	31	0.0	0	0.9	13
	2000	13.7	4.0	5.5	0.0	29	40	0	2.3	17	0.0	0	1.9	14
	2005	16.2	4.0	4.2	2.8	25	26	17	3.2	20	0.0	0	2.0	12
	2006	16.3	4.2	4.1	2.8	26	25	17	3.3	20	0.0	0	2.0	12
	2007	16.5	4.2	4.1	2.8	26	25	17	3.3	20	0.0	0	2.0	12
	2008	16.2	4.2	3.9	2.8	26	24	17	3.3	20	0.0	0	2.0	12
	2009	16.1	4.3	3.7	2.8	26	23	18	3.3	20	0.0	0	2.0	13
	2010	16.9	4.9	3.7	2.9	29	22	17	3.4	20	0.0	0	2.0	12
	2011	16.7	4.9	3.5	2.9	29	21	17	3.5	21	0.0	0	1.9	11
	2012	17.6	5.6	3.6	2.9	32	21	16	3.5	20	0.0	0	2.0	11
	2013	17.8	5.6	3.9	2.9	31	22	16	3.5	20	0.0	0	2.0	11
	2014	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	n.a.	0.3	n.a.

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Pakistan	1980	2.8	0.0	0.3	0.8	0	12	28	1.6	56	0.1	5	0.0	0
	1990	7.7	0.0	1.7	3.0	0	22	38	2.9	38	0.1	2	0.0	0
	2000	16.9	0.2	4.5	6.9	1	27	41	4.8	29	0.5	3	0.0	0
	2005	19.6	0.2	4.5	7.9	1	23	40	6.5	33	0.5	2	0.0	0
	2006	19.6	0.2	4.5	7.9	1	23	40	6.5	33	0.5	2	0.0	0
	2007	19.7	0.2	4.5	8.1	1	23	41	6.5	33	0.5	2	0.0	0
	2008	20.2	0.2	4.5	8.5	1	22	42	6.6	32	0.5	2	0.0	0
	2009	20.6	0.2	4.9	8.5	1	24	41	6.6	32	0.5	2	0.0	0
	2010	21.6	0.2	5.5	8.9	1	25	41	6.6	30	0.5	2	0.0	0
	2011	23.3	0.1	6.5	9.3	0	28	40	6.6	28	0.8	3	0.0	0
	2012	23.6	0.1	6.4	9.5	0	27	40	6.7	29	0.8	3	0.1	0
	2013	23.7	0.1	6.4	9.5	0	27	40	6.8	29	0.8	3	0.1	0
	2014	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.3	n.a.
South Africa	1980	18.4	17.8	0.0	0.0	97	0	0	0.5	3	0.0	0	0.0	0
	1990	34.9	31.1	0.0	0.0	89	0	0	2.0	6	1.8	5	0.0	0
	2000	41.3	37.1	0.3	0.0	90	1	0	2.0	5	1.8	4	0.1	0
	2005	42.1	37.8	0.3	0.0	90	1	0	2.0	5	1.8	4	0.1	0
	2006	42.1	37.2	0.9	0.0	88	2	0	2.0	5	1.8	4	0.1	0
	2007	42.7	37.4	0.3	1.0	88	1	2	2.0	5	1.8	4	0.1	0
	2008	43.1	37.8	0.3	1.0	88	1	2	2.0	5	1.8	4	0.1	0
	2009	44.3	37.9	0.3	2.1	86	1	5	2.0	5	1.8	4	0.1	0
	2010	44.2	37.9	0.3	2.1	86	1	5	2.0	5	1.8	4	0.1	0
	2011	44.2	37.6	0.3	2.3	85	1	5	2.0	5	1.8	4	0.1	0
	2012	45.5	38.8	0.3	2.3	85	1	5	2.0	4	1.9	4	0.1	0
	2013	48.0	41.1	0.3	2.3	86	1	5	2.0	4	1.9	4	0.4	1
	2014	49.1	41.1	0.3	2.3	84	1	5	2.0	4	1.9	4	1.4	3

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Thailand	1980	3.8	0.2	2.4	0.0	5	62	0	1.3	33	0.0	0	0.0	0
	1990	9.7	1.5	3.0	3.0	15	31	31	2.3	23	0.0	0	0.0	0
	2000	27.3	2.6	5.9	15.3	9	22	56	3.2	12	0.0	0	0.4	1
	2005	33.5	2.6	10.1	16.3	8	30	49	3.8	11	0.0	0	0.8	2
	2006	32.3	3.2	8.2	16.3	10	25	50	3.8	12	0.0	0	0.8	2
	2007	34.5	3.9	8.7	17.2	11	25	50	3.8	11	0.0	0	1.0	3
	2008	40.0	3.9	11.4	20.0	10	28	50	3.8	9	0.0	0	1.0	3
	2009	39.4	3.9	10.1	20.6	10	26	52	3.8	10	0.0	0	1.0	3
	2010	41.1	3.9	10.2	21.3	9	25	52	4.7	11	0.0	0	1.0	3
	2011	41.7	4.1	9.9	21.2	10	24	51	5.3	13	0.0	0	1.1	3
	2012	43.0	4.6	10.2	21.4	11	24	50	5.5	13	0.0	0	1.4	3
	2013	44.7	4.6	10.2	22.3	10	23	50	5.5	12	0.0	0	2.1	5
	2014	46.1	4.6	7.8	25.6	10	17	55	5.5	12	0.0	0	2.6	6
Turkey	1980	5.6	1.4	1.8	0.0	25	32	0	2.4	42	0.0	0	0.0	1
	1990	16.7	5.6	2.1	2.2	33	13	13	6.8	41	0.0	0	0.0	0
	2000	27.3	7.4	1.6	7.0	27	6	26	11.2	41	0.0	0	0.1	0
	2005	38.8	9.6	2.5	13.8	25	6	36	12.9	33	0.0	0	0.1	0
	2006	40.5	10.7	2.4	14.3	26	6	35	13.1	32	0.0	0	0.1	0
	2007	40.8	10.7	2.0	14.6	26	5	36	13.4	33	0.0	0	0.2	1
	2008	41.9	10.7	1.8	15.1	25	4	36	13.8	33	0.0	0	0.6	1
	2009	44.8	11.0	1.7	16.6	25	4	37	14.6	33	0.0	0	1.0	2
	2010	49.2	12.1	1.5	18.2	25	3	37	15.8	32	0.0	0	1.5	3
	2011	53.1	12.8	1.6	19.5	24	3	37	17.1	32	0.0	0	2.1	4
	2012	57.3	13.1	1.5	20.5	23	3	36	19.6	34	0.0	0	2.6	5
	2013	64.4	13.1	0.9	24.7	20	1	38	22.3	35	0.0	0	3.5	5
	2014	69.8	15.3	0.8	25.6	22	1	37	23.6	34	0.0	0	4.5	6

TABLE I-1. GENERATION CAPACITY (cont.)

	Year	Total (GW)	Thermal						Hydro		Nuclear		Renewables	
			Capacity (GW)			Share (%)			Capacity (GW)	Share (%)	Capacity (GW)	Share (%)	Capacity (GW)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Kenya	1980	0.5	0.0	0.1	0.0	0	29	0	0.3	68	0.0	0	0.0	3
	1990	0.7	0.0	0.2	0.0	0	23	0	0.5	69	0.0	0	0.1	8
	2000	1.1	0.0	0.3	0.0	0	29	0	0.7	65	0.0	0	0.1	7
	2005	1.2	0.1	0.3	0.0	5	28	0	0.7	56	0.0	0	0.1	11
	2006	1.2	0.1	0.3	0.0	5	28	0	0.7	56	0.0	0	0.1	11
	2007	1.2	0.1	0.3	0.0	5	28	0	0.7	56	0.0	0	0.1	11
	2008	1.2	0.1	0.3	0.0	5	23	0	0.7	61	0.0	0	0.1	12
	2009	1.4	0.1	0.4	0.0	4	28	0	0.8	55	0.0	0	0.2	13
	2010	1.4	0.1	0.4	0.0	4	25	0	0.8	54	0.0	0	0.2	17
	2011	1.5	0.1	0.5	0.0	4	31	0	0.8	50	0.0	0	0.2	15
	2012	1.6	0.1	0.5	0.0	4	31	0	0.8	50	0.0	0	0.2	15
	2013	1.7	0.1	0.6	0.0	3	34	0	0.8	48	0.0	0	0.2	14
	2014	n.a.	n.a.	n.a.	0.0	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	n.a.	0.1	n.a.

Note: The differences between the totals given and the sums of individual values are due to rounding.

Source: Ref. [94]

TABLE I-2. ELECTRICITY PRODUCTION

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Mature markets														
Australia	1980	96.1	69.8	5.2	7.0	73	5	7	13.8	14	0.0	0	0.4	0
	1990	155.0	121.5	3.6	14.4	78	2	9	14.9	10	0.0	0	0.8	0
	2000	210.2	174.2	1.8	16.2	83	1	8	16.7	8	0.0	0	1.2	1
	2005	228.7	181.6	2.8	23.8	79	1	10	15.6	7	0.0	0	4.8	2
	2006	232.8	185.3	3.1	22.7	80	1	10	16.0	7	0.0	0	5.7	2
	2007	243.2	187.2	2.9	31.8	77	1	13	14.5	6	0.0	0	6.7	3
	2008	243.2	184.3	4.1	35.0	76	2	14	12.1	5	0.0	0	7.8	3
	2009	248.8	185.8	4.2	40.1	75	2	16	11.9	5	0.0	0	6.8	3
	2010	252.2	180.9	4.4	45.2	72	2	18	13.5	5	0.0	0	8.1	3
	2011	252.6	173.3	4.1	49.7	69	2	20	16.8	7	0.0	0	8.8	3
	2012	248.9	171.2	4.1	49.6	69	2	20	14.1	6	0.0	0	9.9	4
	2013	248.1	158.9	4.6	52.1	64	2	21	18.2	7	0.0	0	14.3	6
	2014	248.6	158.1	4.7	55.7	64	2	22	13.5	5	0.0	0	16.7	7
New Zealand	1980	22.6	0.4	0.0	1.7	2	0	8	18.9	84	0.0	0	1.5	7
	1990	32.3	0.7	0.0	5.7	2	0	18	23.2	72	0.0	0	2.6	8
	2000	39.2	1.5	0.0	9.6	4	0	24	24.4	62	0.0	0	3.6	9
	2005	43.0	5.9	0.0	9.4	14	0	22	23.3	54	0.0	0	4.3	10
	2006	43.6	5.5	0.0	9.9	13	0	23	23.6	54	0.0	0	4.5	10
	2007	43.7	3.2	0.0	11.8	7	0	27	23.6	54	0.0	0	5.0	12
	2008	43.8	4.8	0.1	10.7	11	0	24	22.3	51	0.0	0	5.8	13
	2009	43.5	3.3	0.0	8.9	8	0	21	24.2	56	0.0	0	6.9	16
	2010	44.9	2.1	0.0	9.9	5	0	22	24.7	55	0.0	0	8.1	18
	2011	44.5	2.2	0.0	8.4	5	0	19	25.1	56	0.0	0	8.7	20
	2012	44.3	3.6	0.0	8.9	8	0	20	22.9	52	0.0	0	8.9	20
	2013	43.3	2.1	0.0	9.1	5	0	21	23.0	53	0.0	0	9.0	21

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
UK	1980	285.3	207.9	33.1	2.1	73	12	1	5.1	2	37.0	13	0.0	0
	1990	319.7	206.4	34.7	5.0	65	11	2	7.2	2	65.7	21	0.7	0
	2000	377.1	122.3	8.4	148.1	32	2	39	7.8	2	85.1	23	5.4	1
	2005	398.4	136.3	5.3	152.6	34	1	38	7.9	2	81.6	20	14.6	4
	2006	397.3	150.5	6.2	140.8	38	2	35	8.4	2	75.5	19	15.9	4
	2007	396.8	137.5	5.1	165.8	35	1	42	8.9	2	63.0	16	16.5	4
	2008	388.9	125.8	6.7	176.2	32	2	45	9.2	2	52.5	13	18.4	5
	2009	376.8	104.4	6.0	166.5	28	2	44	8.9	2	69.1	18	21.8	6
	2010	381.8	108.8	4.8	175.7	28	1	46	6.7	2	62.1	16	23.6	6
	2011	367.5	109.4	3.1	146.5	30	1	40	8.6	2	69.0	19	30.8	8
	2012	363.8	144.2	3.1	100.1	40	1	28	8.3	2	70.4	19	37.9	10
	2013	356.6	130.2	2.5	95.7	37	1	27	7.6	2	70.6	20	49.9	14
	2014	332.7	98.3	2.4	101.2	30	1	30	8.8	3	63.7	19	58.2	18
Germany	1980	467.6	293.5	26.7	66.0	63	6	14	20.3	4	55.6	12	5.4	1
	1990	550.0	321.6	10.4	40.5	58	2	7	19.8	4	152.5	28	5.3	1
	2000	576.5	304.2	4.8	52.5	53	1	9	26.0	5	169.6	29	19.5	3
	2005	622.6	297.7	12.0	74.0	48	2	12	26.4	4	163.1	26	49.4	8
	2006	639.5	298.4	11.0	76.8	47	2	12	26.8	4	167.3	26	59.3	9
	2007	640.6	308.3	10.0	79.6	48	2	12	28.1	4	140.5	22	74.1	12
	2008	640.4	285.4	9.7	90.3	45	2	14	26.5	4	148.5	23	80.0	12
	2009	595.6	260.3	10.1	82.1	44	2	14	24.7	4	134.9	23	83.6	14
	2010	633.0	273.5	8.7	90.4	43	1	14	27.4	4	140.6	22	92.5	15
	2011	613.1	272.4	7.2	87.2	44	1	14	23.5	4	108.0	18	114.8	19
	2012	629.8	287.0	7.6	77.6	46	1	12	27.8	4	99.5	16	130.3	21
	2013	635.3	298.5	6.4	66.8	47	1	11	26.3	4	97.3	15	140.0	22
	2014	616.0	279.7	5.3	57.7	45	1	9	23.4	4	97.1	16	152.8	25

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Lithuania	1990	28.4	0.0	4.2	6.8	0	15	24	0.4	1	17.0	60	0.0	0
	2000	11.4	0.0	0.7	1.6	0	6	14	0.6	6	8.4	74	0.0	0
	2005	14.8	0.0	0.4	3.0	0	3	20	0.8	6	10.3	70	0.0	0
	2006	12.5	0.0	0.3	2.5	0	3	20	0.8	6	8.7	69	0.0	0
	2007	14.0	0.0	0.4	2.4	0	3	17	1.0	7	9.8	70	0.2	1
	2008	13.9	0.0	0.6	2.0	0	4	15	1.0	7	9.9	71	0.2	1
	2009	15.4	0.0	0.7	2.1	0	5	14	1.1	7	10.9	71	0.3	2
	2010	5.7	0.0	0.6	3.2	0	11	55	1.3	23	0.0	0	0.4	6
	2011	4.8	0.0	0.2	2.7	0	4	55	1.1	22	0.0	0	0.6	13
	2012	5.0	0.0	0.2	2.9	0	5	57	0.9	19	0.0	0	0.8	15
	2013	4.7	0.0	0.1	2.5	0	2	52	1.1	22	0.0	0	0.9	19
Poland	1980	121.9	114.5	3.5	0.1	94	3	0	3.3	3	0.0	0	0.4	0
	1990	136.3	131.0	1.6	0.1	96	1	0	3.3	2	0.0	0	0.3	0
	2000	145.2	137.7	1.9	0.9	95	1	1	4.1	3	0.0	0	0.6	0
	2005	156.9	143.3	2.8	5.2	91	2	3	3.8	2	0.0	0	1.9	1
	2006	161.7	148.7	2.9	4.6	92	2	3	3.0	2	0.0	0	2.5	2
	2007	159.3	145.8	2.8	4.5	91	2	3	2.9	2	0.0	0	3.3	2
	2008	155.3	140.6	2.7	4.7	91	2	3	2.7	2	0.0	0	4.5	3
	2009	151.7	134.9	2.7	4.8	89	2	3	3.0	2	0.0	0	6.4	4
	2010	157.7	138.4	2.9	4.8	88	2	3	3.5	2	0.0	0	8.0	5
	2011	163.5	141.6	2.5	5.8	87	1	4	2.8	2	0.0	0	10.9	7
	2012	162.1	136.5	2.0	6.3	84	1	4	2.5	2	0.0	0	14.9	9
	2013	164.5	139.8	1.8	5.1	85	1	3	3.0	2	0.0	0	14.7	9
	2014	158.5	132.1	1.8	5.0	83	1	3	3.2	2	0.0	0	16.4	10

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
US	1980	2427.3	1242.9	263.2	370.5	51	11	15	278.8	11	266.2	11	5.8	0
	1990	3218.6	1699.6	130.6	381.7	53	4	12	289.0	9	611.6	19	106.1	3
	2000	4052.7	2129.5	118.5	634.3	53	3	16	280.0	7	797.7	20	92.7	2
	2005	4294.4	2154.0	141.3	782.8	50	3	18	297.9	7	810.7	19	107.6	3
	2006	4300.8	2127.8	78.6	842.8	49	2	20	317.7	7	816.2	19	117.8	3
	2007	4349.8	2118.5	78.1	915.2	49	2	21	275.5	6	836.6	19	125.9	3
	2008	4368.3	2132.6	57.8	910.2	49	1	21	282.0	6	837.8	19	147.9	3
	2009	4188.2	1892.7	50.4	949.8	45	1	23	298.4	7	830.2	20	166.7	4
	2010	4378.4	1994.2	48.1	1017.9	46	1	23	286.3	7	838.9	19	193.0	4
	2011	4349.6	1875.4	39.5	1045.3	43	1	24	344.7	8	821.4	19	223.3	5
	2012	4290.5	1643.4	33.1	1264.6	38	1	29	298.3	7	801.1	19	250.1	6
	2013	4301.6	1721.9	36.2	1148.8	40	1	27	290.2	7	821.6	19	283.0	7
	2014	4330.2	1717.2	40.6	1145.8	40	1	26	281.4	6	830.0	19	315.1	7
Chile	1980	11.8	1.9	1.7	0.2	16	15	1	7.9	67	0.0	0	0.1	1
	1990	18.4	6.5	1.8	0.2	36	10	1	8.9	49	0.0	0	1.0	5
	2000	40.1	8.5	1.7	10.4	21	4	26	18.5	46	0.0	0	0.9	2
	2005	52.5	7.2	3.4	13.6	14	6	26	26.5	50	0.0	0	1.8	3
	2006	55.3	10.6	2.7	11.4	19	5	21	29.1	53	0.0	0	1.4	3
	2007	58.5	13.3	14.8	4.6	23	25	8	23.1	40	0.0	0	2.7	5
	2008	59.7	14.1	16.1	2.2	24	27	4	24.2	41	0.0	0	3.1	5
	2009	60.7	14.9	12.1	3.9	25	20	6	25.3	42	0.0	0	4.5	7
	2010	60.4	16.9	8.5	10.7	28	14	18	21.7	36	0.0	0	2.7	4
	2011	65.7	19.6	6.4	13.7	30	10	21	21.0	32	0.0	0	5.0	8
	2012	69.8	25.3	6.1	12.8	36	9	18	20.2	29	0.0	0	5.3	8
	2013	72.4	28.7	6.1	12.0	40	8	17	20.0	28	0.0	0	5.6	8

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Colombia	1980	20.4	1.6	0.4	3.9	8	2	19	14.3	70	0.0	0	0.2	1
	1990	36.4	3.7	0.4	4.5	10	1	12	27.5	76	0.0	0	0.3	1
	2000	43.1	2.2	0.1	8.3	5	0	19	32.1	74	0.0	0	0.5	1
	2005	50.3	2.5	0.1	7.4	5	0	15	39.8	79	0.0	0	0.6	1
	2006	53.8	2.9	0.1	7.4	5	0	14	42.7	79	0.0	0	0.6	1
	2007	55.2	3.5	0.2	6.6	6	0	12	44.4	80	0.0	0	0.6	1
	2008	55.9	3.0	0.2	5.8	5	0	10	46.4	83	0.0	0	0.6	1
	2009	57.1	4.2	0.3	10.9	7	1	19	41.1	72	0.0	0	0.6	1
	2010	59.4	4.1	0.5	12.0	7	1	20	40.4	68	0.0	0	2.5	4
	2011	61.0	2.3	0.1	7.6	4	0	13	48.9	80	0.0	0	2.0	3
	2012	62.3	3.4	0.3	9.0	5	1	14	47.6	76	0.0	0	2.0	3
	2013	64.6	6.3	0.3	11.7	10	0	18	44.3	69	0.0	0	2.0	3
Transition and potential markets														
China	1980	300.6	164.1	77.6	0.7	55	26	0	58.2	19	0.0	0	0.0	0
	1990	621.2	442.8	49.0	2.8	71	8	0	126.7	20	0.0	0	0.0	0
	2000	1356.2	1062.1	46.1	5.8	78	3	0	222.4	16	16.7	1	3.1	0
	2005	2502.5	1971.8	61.3	11.9	79	2	0	397.0	16	53.1	2	7.4	0
	2006	2869.8	2301.9	52.0	14.2	80	2	0	435.8	15	54.8	2	11.1	0
	2007	3287.5	2659.6	34.3	30.5	81	1	1	485.3	15	62.1	2	15.7	0
	2008	3482.0	2744.1	23.4	31.0	79	1	1	585.2	17	68.4	2	29.8	1
	2009	3742.0	2940.9	16.5	50.8	79	0	1	615.6	16	70.1	2	48.0	1
	2010	4208.0	3250.4	13.3	69.0	77	0	2	722.2	17	73.9	2	79.3	2
	2011	4715.8	3723.2	7.9	84.0	79	0	2	698.9	15	86.4	2	115.4	2
	2012	4994.1	3784.9	6.8	85.7	76	0	2	872.1	17	97.4	2	147.2	3
	2013	5368.6	4044.3	7.0	97.7	75	0	2	920.9	17	110.6	2	188.1	4
	2014	5583.4	4051.7	7.2	113.6	73	0	2	1065.5	19	131.4	2	214.0	4

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
India	1980	120.4	61.5	8.8	0.6	51	7	1	46.6	39	3.0	2	0.0	0
	1990	292.7	191.6	13.3	10.0	65	5	3	71.7	24	6.1	2	0.0	0
	2000	569.7	390.2	29.2	56.0	68	5	10	74.5	13	16.9	3	3.0	1
	2005	715.7	478.5	25.4	75.5	67	4	11	107.9	15	17.3	2	11.1	2
	2006	773.8	516.0	23.8	79.4	67	3	10	120.4	16	18.8	2	15.5	2
	2007	823.6	539.3	24.7	95.3	65	3	12	127.9	16	17.0	2	19.5	2
	2008	848.4	580.7	25.6	86.9	68	3	10	116.8	14	14.9	2	23.5	3
	2009	917.3	616.5	22.1	116.1	67	2	13	113.1	12	18.6	2	30.8	3
	2010	979.4	658.0	24.4	113.3	67	2	12	123.1	13	26.3	3	34.4	4
	2011	1074.5	717.4	24.1	114.2	67	2	11	143.6	13	32.3	3	43.0	4
	2012	1127.6	801.3	22.7	93.9	71	2	8	125.8	11	32.9	3	50.9	5
	2013	1194.1	854.2	23.0	75.0	72	2	6	149.1	12	34.2	3	58.5	5
	2014	1295.7	956.9	23.7	69.3	74	2	5	142.7	11	35.9	3	67.1	5
Indonesia	1980	7.5	0.0	6.2	0.0	0	82	0	1.3	18	0.0	0	0.0	0
	1990	32.7	9.8	15.3	0.7	30	47	2	5.7	17	0.0	0	1.1	3
	2000	93.3	34.0	18.3	26.1	36	20	28	10.0	11	0.0	0	4.9	5
	2005	127.7	51.8	39.1	19.5	41	31	15	10.7	8	0.0	0	6.6	5
	2006	133.8	58.6	38.7	20.2	44	29	15	9.6	7	0.0	0	6.7	5
	2007	143.5	63.8	37.7	23.6	44	26	16	11.3	8	0.0	0	7.1	5
	2008	150.4	61.4	42.9	26.2	41	29	17	11.5	8	0.0	0	8.4	6
	2009	156.8	65.9	35.4	34.8	42	23	22	11.4	7	0.0	0	9.4	6
	2010	169.8	68.4	34.2	40.2	40	20	24	17.5	10	0.0	0	9.5	6
	2011	183.4	81.0	42.3	38.1	44	23	21	12.4	7	0.0	0	9.6	5
	2012	195.9	95.3	32.7	45.5	49	17	23	12.8	7	0.0	0	9.6	5
	2013	212.0	106.3	31.3	48.4	50	15	23	0.0	7	0.0	0	10.1	5

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Malaysia	1980	10.0	0.0	8.5	0.1	0	85	1	1.4	14	0.0	0	0.0	0
	1990	23.0	2.9	10.6	5.5	13	46	24	4.0	17	0.0	0	0.0	0
	2000	69.3	7.7	3.6	51.0	11	5	74	7.0	10	0.0	0	0.0	0
	2005	82.7	20.0	2.2	55.3	24	3	67	5.2	6	0.0	0	0.0	0
	2006	89.8	20.7	3.1	59.5	23	3	66	6.4	7	0.0	0	0.0	0
	2007	97.5	27.0	2.2	61.8	28	2	63	6.5	7	0.0	0	0.0	0
	2008	97.8	26.2	1.7	62.4	27	2	64	7.5	8	0.0	0	0.0	0
	2009	116.0	33.3	3.5	71.0	29	3	61	7.0	6	0.0	0	1.2	1
	2010	124.8	42.8	3.7	70.8	34	3	57	6.5	5	0.0	0	1.0	1
	2011	129.3	53.0	9.5	58.2	41	7	45	7.6	6	0.0	0	1.1	1
	2012	134.4	55.8	6.0	62.6	42	4	47	9.1	7	0.0	0	0.9	1
	2013	145.1	59.6	6.2	64.1	41	4	44	14.2	10	0.0	0	1.0	1
Philippines	1980	18.0	0.2	12.2	0.0	1	68	0	3.5	20	0.0	0	2.1	12
	1990	26.3	1.9	12.4	0.0	7	47	0	6.1	23	0.0	0	5.9	22
	2000	45.3	16.7	9.2	0.0	37	20	0	7.8	17	0.0	0	11.6	26
	2005	56.6	15.3	6.1	16.9	27	11	30	8.4	15	0.0	0	9.9	18
	2006	56.8	15.3	4.7	16.4	27	8	29	9.9	18	0.0	0	10.5	19
	2007	59.6	16.8	5.1	18.8	28	9	32	8.6	14	0.0	0	10.3	17
	2008	60.8	15.7	4.9	19.6	26	8	32	9.8	16	0.0	0	10.8	18
	2009	61.9	16.5	5.4	19.9	27	9	32	9.8	16	0.0	0	10.4	17
	2010	67.7	23.3	7.1	19.5	34	10	29	7.8	12	0.0	0	10.0	15
	2011	69.2	25.3	3.4	20.6	37	5	30	9.7	14	0.0	0	10.1	15
	2012	72.9	28.3	4.3	19.6	39	6	27	10.3	14	0.0	0	10.5	14
	2013	75.3	32.1	4.5	18.8	43	6	25	10.0	13	0.0	0	9.9	13

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Pakistan	1980	15.0	0.0	0.2	6.1	0.0	1	40	8.7	58	0.0	0	0.0	0
	1990	37.7	0.0	7.7	12.7	0.0	21	34	16.9	45	0.3	1	0.0	0
	2000	68.1	0.2	26.9	21.8	0.0	39	32	17.2	25	2.0	3	0.0	0
	2005	93.6	0.1	18.9	41.3	0.0	20	44	30.9	33	2.5	3	0.0	0
	2006	98.2	0.1	28.0	35.8	0.0	29	36	32.0	33	2.3	2	0.0	0
	2007	95.7	0.1	30.8	32.9	0.0	32	34	28.7	30	3.1	3	0.0	0
	2008	91.6	0.1	32.4	29.7	0.0	35	32	27.8	30	1.6	2	0.0	0
	2009	95.4	0.1	36.2	28.1	0.0	38	29	28.1	29	2.9	3	0.0	0
	2010	94.4	0.1	33.2	25.9	0.0	35	27	31.8	34	3.4	4	0.0	0
	2011	95.1	0.1	33.6	27.7	0.0	35	29	28.5	30	5.3	6	0.0	0
	2012	96.1	0.1	34.5	27.1	0.0	36	28	29.9	31	4.6	5	0.0	0
	2013	95.3	0.1	33.9	23.1	0.0	36	24	34.4	36	3.8	4	0.0	0
South Africa	1980	99.0	97.9	0.0	0.0	99.0	0	0	1.0	1	0.0	0	0.0	0
	1990	167.2	155.9	0.0	0.0	93.0	0	0	2.9	2	8.4	5	0.0	0
	2000	210.7	193.4	0.0	0.0	92.0	0	0	3.9	2	13.0	6	0.3	0
	2005	244.9	229.0	0.1	0.0	94.0	0	0	4.2	2	11.3	5	0.3	0
	2006	253.8	237.6	0.1	0.0	94.0	0	0	5.8	2	10.0	4	0.3	0
	2007	263.5	246.9	1.2	0.0	94.0	0	0	3.8	1	11.3	4	0.3	0
	2008	258.3	240.8	0.1	0.0	93.0	0	0	4.0	2	13.0	5	0.4	0
	2009	249.6	232.2	0.0	0.0	93.0	0	0	4.1	2	12.8	5	0.4	0
	2010	259.6	241.8	0.2	0.0	93.0	0	0	5.1	2	12.1	5	0.4	0
	2011	262.5	243.4	0.2	0.0	93.0	0	0	5.0	2	13.5	5	0.4	0
	2012	257.9	239.3	0.2	0.0	93.0	0	0	4.9	2	13.1	5	0.4	0
	2013	256.1	236.4	0.2	0.0	92.0	0	0	4.7	2	14.4	6	0.4	0
	2014	252.6	230.3	0.4	0.0	91.0	0	0	4.5	2	16.9	7	0.4	0

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Thailand	1980	14.4	1.4	11.7	0.0	10	81	0	1.3	9	0	0	0.0	0
	1990	44.2	11.1	10.4	17.8	25	23	40	5.0	11	0	0	0.0	0
	2000	96.0	17.8	10.0	61.6	19	10	64	6.0	6	0	0	0.5	1
	2005	132.2	20.5	8.7	95.6	16	7	72	5.8	4	0	0	1.5	1
	2006	138.7	25.3	8.5	95.3	18	6	69	8.1	6	0	0	1.5	1
	2007	143.4	30.8	3.9	98.8	21	3	69	8.1	6	0	0	1.8	1
	2008	147.4	31.8	1.7	104.3	22	1	71	7.1	5	0	0	2.6	2
	2009	148.4	30.0	0.7	107.4	20	0	72	7.1	5	0	0	3.1	2
	2010	159.5	30.0	1.2	119.3	19	1	75	5.5	3	0	0	3.4	2
	2011	156.0	34.8	2.1	106.6	22	1	68	8.2	5	0	0	4.4	3
	2012	166.6	33.4	2.4	117.1	20	1	70	8.8	5	0	0	5.0	3
	2013	168.0	32.7	1.7	120.2	19	1	72	5.6	3	0	0	7.8	5
Turkey	1980	23.3	6.0	5.8	0.0	26	25	0	11.3	49	0	0	0.1	1
	1990	57.5	20.2	3.9	10.2	35	7	18	23.1	40	0	0	0.1	0
	2000	124.9	38.2	9.3	46.2	31	7	37	30.9	25	0	0	0.3	0
	2005	162.0	43.2	5.5	73.4	27	3	45	39.6	24	0	0	0.3	0
	2006	176.3	46.7	4.3	80.7	26	2	46	44.2	25	0	0	0.4	0
	2007	191.6	53.4	6.5	95.0	28	3	50	35.9	19	0	0	0.7	0
	2008	198.4	57.7	7.5	98.7	29	4	50	33.3	17	0	0	1.2	1
	2009	194.8	55.7	4.8	96.1	29	2	49	36.0	18	0	0	2.3	1
	2010	211.2	55.0	2.2	98.1	26	1	46	51.8	25	0	0	4.0	2
	2011	229.4	66.2	0.9	104.0	29	0	45	52.3	23	0	0	5.9	3
	2012	239.5	68.0	1.6	104.5	28	1	44	57.9	24	0	0	7.5	3
	2013	241.2	65.1	1.7	105.2	27	1	44	59.3	25	0	0	9.9	4

TABLE I-2. ELECTRICITY PRODUCTION (cont.)

	Year	Total (TW·h)	Thermal						Hydro		Nuclear		Renewable	
			Production (TW·h)			Share (%)			Production (TW·h)	Share (%)	Production (TW·h)	Share (%)	Production (TW·h)	Share (%)
			Coal	Oil	Gas	Coal	Oil	Gas						
Kenya	1980	1.6	0.0	0.4	0.0	0	26	0	1.1	65	0	0	0.1	9
	1990	3.2	0.0	0.2	0.0	0	7	0	2.5	77	0	0	0.5	16
	2000	4.2	0.0	2.1	0.0	0	51	0	1.3	32	0	0	0.7	18
	2005	6.0	0.0	1.6	0.0	0	27	0	3.0	51	0	0	1.3	22
	2006	6.5	0.0	1.9	0.0	0	29	0	3.3	51	0	0	1.3	21
	2007	6.7	0.0	1.8	0.0	0	28	0	3.5	52	0	0	1.3	20
	2008	6.8	0.0	2.4	0.0	0	36	0	2.8	42	0	0	1.5	22
	2009	6.9	0.0	3.0	0.0	0	44	0	2.2	32	0	0	1.7	24
	2010	7.5	0.0	2.3	0.0	0	30	0	3.4	46	0	0	1.8	24
	2011	7.8	0.0	2.6	0.0	0	33	0	3.5	44	0	0	1.8	23
	2012	8.3	0.0	2.1	0.0	0	25	0	4.3	52	0	0	1.9	23
	2013	8.9	0.0	2.0	0.0	0	22	0	4.7	53	0	0	2.2	25

Note: The differences between the totals given and the sums of individual values are due to rounding.

Source: Ref. [94]

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ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BETTA	British Electricity Trading and Transmission Arrangements
BOO	Build own operate
BOT	Build operate transfer
CCGTs	Combined cycle gas turbines
CCS	Carbon dioxide capture and storage
CDM	Clean development mechanism
CERC	Central Electricity Regulatory Commission
CFD	Contract for difference
CHP	Combined heat and power
CNE	National Energy Commission
CO_2	Carbon dioxide
EGAT	Electricity Generating Authority of Thailand
EMRA	Energy Market Regulatory Authority
ENSO	El Niño Southern Oscillation
EPIRA	Electric Power Industry Reform Act
EPPO	Energy Policy and Planning Office
ERC	Energy Regulatory Commission
ETS	Emissions trading scheme
EU	European Union
FIT	Feed-in tariff
GHG	Greenhouse gas
IPP	Independent power producer
KPLC	Kenya Power and Lighting Company Limited
LOLP	Loss of load probability
MEA	Metropolitan Electricity Authority
MRET	Mandatory renewable energy target
MOE	Ministry of Energy
NCCPE	National Control Commission for Prices and Energy
NDRC	National Development and Reform Commission
NEM	National electricity market

NEPRA	National Electric Power Regulatory Authority
NER	National Electricity Regulator
NETA	New electricity trading arrangement
NPC	National Power Corporation
NPCIL	Nuclear Power Corporation of India Ltd.
NPP	Nuclear power plant
NTDC	National Transmission and Dispatch Company
Ofgem	Office of Gas and Electricity Markets
OTC	Over the counter
PAEC	Pakistan Atomic Energy Commission
PEA	Provincial Electricity Authority
PLN	Perusahaan Listrik Negara (National Electric Power Company)
PPA	Power purchase agreement
PPIB	Private Power and Infrastructure Board
REFIT	Renewable energy feed-in tariff
ROC	Renewable obligation certificate
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
SPP	Small power producers
TEAS	Turkish Electricity Generation and Transmission Company
TEDAS	Turkish Electricity Distribution Company
TEIAS	Turkish Electricity Transmission Corp.
TETAS	Turkish Electricity Trading and Contracting Corp.
TNB	Tenaga Nasional Berhad
TOOR	Transfer of operating rights
TPPs	thermal power plants
TSO	Transmission system operator
UK	United Kingdom
USA	United States of America
VSPP	Very small power producer
WAPDA	Water and Power Development Authority
WESM	Wholesale electricity spot market

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