ENERGY MARKET INTEGRATION IN EAST ASIA:

ENERGY TRADE, CROSS BORDER ELECTRICITY, AND PRICE MECHANISM

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CHAPTER 1
Introduction

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Background and Objectives

Research on *Energy Market Integration (EMI)* has been the focus of many scholars, researchers, and leaders in the energy field as evidences, particularly in Europe and America, tend to show the benefits from such market integration. The Association of Southeast Asian Nations (ASEAN) community, aiming to achieve the ASEAN Economic Community, will need to address the issue on EMI in a more explicit way as it has been a driving force for economic growth in the region so far. It must be noted that for EMI and energy trade to occur, the basic prerequisite is to have sufficient available connecting infrastructure between markets and the supporting regulatory and political conditions (Han, 2014). A well-coordinated and effective resource allocation could happen only if markets are contestable and fully competitive, and countries may give up their policy on sovereignty from "own-regulation" to "deregulation" in order to join the regional market integration (Kimura, *et al*., 2013).

The Economic Research Institute for ASEAN and East Asia (ERIA) has conducted the EMI studies for several years, and the studies have been promoted by East Asia governments to deepen understanding on matters impacting on energy trade liberalisation and investment, energy infrastructure, pricing reform, and deregulation of domestic energy markets.

Previous EMI studies focused on the review of the regional commitment of East Asian Summit (EAS) countries, the benefits from EMI, the electricity market, theories, subsidies, and renewable energy (RE). In the EMI 2013-2014, the theme was chosen to provide more focus on the energy trade in the ASEAN and East Asian countries, though other energy-related issues are also covered in this study.

The EMI study was commissioned by ERIA with the participation of scholars, researchers, and government stakeholders in EAS countries. The group met two times during the research process and peer reviews commenced afterwards. The group also took as leverage the 19th Energy Cooperation Task Force (ECTF) meeting held on 12 June 2014 in the heritage city of Luang Prabang, Lao People's Democratic Republic (Lao PDR), to present the study's preliminary findings to the Senior Officers on Energy (SOE) leaders from EAS countries, and to get their comments and feedbacks.

This EMI study provides analytical perspectives on constraints and barriers, and the measures that countries could take to address issues—from institutional, financial, and human resources—to realise the potential benefits from energy trade-related matters, power connectivity, and other EMI-involved mechanisms.

Outline of the Chapters

There are 12 chapters in this book. Chapters 2-5 provide analyses on the energy trading—either at specific country case or at the regional scale—by looking at various perspectives on energy trade-related commodities and aspects. Chapters 6-7 provide national and regional analyses of power connectivity in the region, and Chapters 8-12 provide analyses of price mechanism in the EMI.

Chapter 2 by Youngho Chang focuses on "Energy Commodity Trading in Singapore". The paper examines how Singapore has become successful in energy trading by analysing what can be attributed to the success, and finally, draws some lessons learned from the success story. Singapore has successfully transformed its well-established Centerport center into an energy trading hub in Asia and the world. The most critical factor in the successful transformation was the firm decision of the Singapore government to strengthen its competiveness in oil storage and blending in the oil refinery sector. To build its refinery sector, Singapore offered an attractive concessionary tax system and implemented a unique but attractive oil trader program—an approved oil trader program, and later, a global trader program incorporating oil traders as well as other commodity traders. This program helped oil traders and trading companies to do oil trading business in Singapore at lower costs but for higher profits. Along with the entire supply chain of oil products, Singapore has built an integrated oil trading system from refining to storing and tanking, and from trading to financing, which in turn allowed Singapore more flexibility and liquidity in meeting diverse demands and trading various oil products. Apart from the economic costs, Singapore offered a favorable time zone position between North America and Europe, better living conditions, and language options.

Chapter 3 by Sangeeta Sharma presents the "Energy Trade Practices in India: Review of Tariff and Non-Tariff Barriers in Relation to ASEAN". The paper reviews the energy sector in India and focuses on the scope of India's energy trade with other countries in the EAS region, specially the Association of South East Asian Nations (ASEAN); and its barriers and limitations. It suggests that India has the capacity to boost its energy trade in both domestic and international markets. The EAS region has several factors—geographical proximity, gaps in energy supply and demand, and different socioeconomic conditions—which are conducive to energy cooperation between India and its neighbors. Each country in the region has some comparative advantage that could be harnessed for a mutually beneficial energy trade within the region. Presently, India has a weak energy trade network, which could be strengthened for optimal advantage in the utilisation of its energy resources.

Chapter 4 by Anindya Bhattacharya M.S., and Tania Bhattacharya focuses on "ASEAN–India Gas Cooperation: Redefining India's 'Look East' Policy with Myanmar". This paper demonstrates that India is eventually going to depend more on gas for its energy supply after coal, and that to meet its domestic demand, India's homegrown gas supply is not sufficient. India currently imports more than 75% of its energy requirement from Qatar. Given future demand growth, the increasing supply volatility of Middle Eastern gas and increasing gas price (including Asian premium) will make the option of Middle East dependence more expensive and vulnerable for India. Since more than 27% of landed gas price and liquefied natural gas (LNG) in the country is transport cost, it is therefore important to reduce the distance of transporting them. In terms of exploring more energy cooperation with the ASEAN and East Asia, India's "East Look Policy" had not produced any good result so far. However, given the rise of Myanmar in the geopolitical map of this region with its untapped natural resources, which are potentially exportable, and as a border country to India, Myanmar is envisaged to play a strategic role for India to meet its near- to mid-term gas demand more economically. India can procure gas from Myanmar either by direct resource extraction or by using Myanmar as a transit country to bring in gas from other ASEAN countries, especially by linking to the ASEAN Gas Network. This study further reveals that India is lagging far behind China in terms of hard gas infrastructure development in Myanmar, but it also identifies India's potential of soft linkage development within Myanmar's natural gas sector. Existing large-scale infrastructure development brings several environmental and social externalities that are not adequately addressed, but with India's support, Myanmar can overcome such externalities as well.

Chapter 5 by Tri Widodo emphasises on "The Welfare Impacts of Price Equalisation in Energy Market Integration". The paper examines the pattern of ASEAN countries' comparative advantages in energy products by applying Trade Balance Index (TBI). Comparative advantage indicates what commodity trade of a country can be classified into "net-exporter" or "net-importer". TBI shows that coal, lignite and peat, and gas (natural and manufactured) are the upfront energy commodity line that share positive index. Meanwhile, briquettes, coke and semi-coke, lignite or peat, and retort carbon are the least competitive basket in energy market. Finally, it is suggested that the positive total welfare impact of price equalization (increase) in ASEAN is contributed by energy products such as coal, lignite and peat, and gas—natural and manufactured.

Chapter 6 by Yu Sheng,Yanrui Wu, Xunpeng Shi, and Dandan Zhang focuses on "Market Integration and Energy Trade Efficiency: An Application of Malmqvist Index to Analyse Multi-products Energy Trade". The paper uses the data envelope analyses—the Malmquist index methods—to examine the bilateral trade efficiency in energy products across countries and its determinants between 1995 and 2008. The empirical results showed that, under the assumption of a flexible substitution between coal, petrol, and gas, the efficiency/potential of bilateral energy trade has been increasing, in particular in the EAS region, asymmetrically between different energy products.

Chapter 7 by Yanfei Li and Youngho Chang focuses on “Infrastructure Investments for Power Trade and Transmission in ASEAN+2: Costs, Benefits, Long-term Contracts and Prioritised Developments”. This paper examines the financial viability of investments on cross-border power transmission capacities by establishing a whole-grid/system simulation model to assess the financial viability, as well as commercial viability, of new transmission projects with optimized pattern of power trade, and if the approach is also suitable for optimizing the planning of new transmission capacities. Results showed that the existing planning of power transmission infrastructure in the region, called ASEAN Power Grid plus China and India (APG+2), stands as a commercially and financially viable plan.

Chapter 8 by Chea Piseth and Chea Sophearin focuses on “Assessment of Power Trade Benefits from Hydropower Power Projects in Lower Mekong Basin”. Greater Mekong Subregion (GMS) has an enormous potential of hydropower resources, on both a large and small scale, to address the regional energy requirement in significant capacity. GMS also has various experiences in regional power trading with the development of privately owned and financed hydropower projects. This paper outlines the basis for evaluating the benefits of hydropower development and power trade (especially using hydropower-sourced energy) in the GMS region. The research consists of three sections. The first section reviews the experience and current status of the regional power trade and power development in GMS, including hydropower. The second section focuses on determining the benefits (focusing on net economic benefit and carbon dioxide [CO_2] emission) accruing to each country, explaining the value of avoided generation costs and the annual cost of the hydropower project. The third section explains the key issues as lessons learned in GMS power trade.

Chapter 9 by Yanrui Wu focuses on "Deregulation, Competition and Market Integration in China's Electricity Sector". The paper presents an updated and expanded review about reforms in China's electricity sector. It aims to examine the impact of reforms on competition, deregulation and electricity market integration in China. For a long time, China's electricity sector has been heavily regulated with the state-owned company, namely State Power Corporation, being the dominant player in the market. Since 2002, China has undertaken major reform initiative to introduce competition and unbundling and hence raise efficiency in the electricity sector. However, it is argued that restructuring has not delivered its anticipated benefits and further reforms are needed. Given the sheer size and complexity of China's electricity sector, understanding its development has important implications not only for China's domestic policies but also for the promotion of EMI in East Asia.

Chapter 10 by Dandan Zhang, Xunpeng Shi, and Yu Sheng focuses on "Enhanced Measurement of Energy Market Integration in East Asia: An Application of Dynamic Principal Component Analysis". This paper uses the dynamic principal component analyses to measure the EMI and its change in the EAS region between 1995 and 2010. The proposed measure covers EMI from four important aspects that include (i) energy trade liberalisation, (ii) investment liberalisation, (iii) energy infrastructure development, (iv) domestic market openness, and (v) energy pricing liberalisation. Results show that significant progress has been made for EMI in the EAS region though there are cross-country disparities in different aspects.

Chapter 11 by Romeo Pacudan focuses on "Electricity Price Impacts of Feed-in Tariff Policies: The Cases of Malaysia, the Philippines and Thailand". This paper examines the implications of feed-in tariff policies on electricity prices in Malaysia, the Philippines, and Thailand and how these countries have considered measures to minimise impacts on low-income households in their design of feed-in tariff policies. Some ASEAN member countries such as Malaysia, the Philippines, and Thailand have recently introduced feed-in tariff schemes to promote private sector investments on grid-connected renewable energy technologies where feed-in tariff payments are being supported by electricity ratepayers. This paper also reviews existing electricity market structures, electricity pricing policies, and feed-in tariff policies; and analyses measures introduced by these countries to reduce the financial burden of feed-in tariff to low-income households.

Chapter 12 by Han Phoumin and Fukunari Kimura focuses on "Trade-off Relationship between Energy Intensity—thus Energy Demand—and Income Level: Empirical Evidence and Policy Implications for ASEAN and East Asia Countries". This study was motivated by the recent shift of energy demand's gravity to Asia due to decades of robust and stable economic growth in the region. Such an economic growth has correspondingly led to increases in the per capita income of the emerging economies in ASEAN and East Asia. Past empirical studies showed that energy demand—thus, energy intensity—tends to grow at the early stage of development. However, curbing the energy intensity remains central to green growth policy. This study employs a panel data model, pool-OLS, and historical time-series data of individual countries with Vector Error Correction Model (ECM) for the analyses of the above objectives. The findings have suggested three major implications. One, it finds that energy intensity—thus energy demand—has a trade-off relationship with income level, which contributes to the theory of energy demand. Two, energy intensity has a trade-off relationship with income level, albeit the fact that each country has a different threshold level, implying that whatever the level of per capita income a particular country has, that country can reduce energy intensity if it has the right policies in place. And three, countries with persistently increasing energy intensity will need to look into their energy efficiency policies more aggressively to ensure that structural changes in the economy do keep the energy efficiency policy to its core.

Chapter 13 by Dayong Zhang and David C. Broadstock focuses on "Impacts of International Oil Price Shocks on Consumption Expenditure in ASEAN and East Asia". This paper examines the impact of international oil shocks upon consumption expenditure in selected ASEAN and East Asian economies. Including oil shocks into a standard macroeconomic model of consumption clearly revealed the reaction of consumption to oil price changes. After the 2008 global financial crisis, government investment and export trade, which are traditionally the two main driving forces behind economic growth in the region, have dropped significantly. This gives governments in the region additional incentive to boost domestic consumption. Therefore, policy makers need to understand how international oil shocks can affect consumption expenditure. A theory-based empirical consumption function is extended by adding oil prices in order to show where and how consumption in this region responds to international oil shocks.

Policy Implications

Energy Trade-related Policy Recommendations

a. Taking lessons from Singapore's successful experiences in the trading hub of energy products, this study offers some policy recommendations that could harness the benefits from the free trade of energy-related products among the ASEAN and EAS countries. The key finding was that Singapore had undertaken policies to provide strong economic incentives to investors by having well-established trading programs as an impetus for energy commodity trading to occur in a country. This successful experience points to recommendations where the government will need to have an assertive role in economic development by investing in infrastructure and education, implementing economic planning, having a control over key macroeconomic variables, coordinating public sector investment, and attracting private sector investment. All these will need coordinated actions and serious commitment to plan and implement them.

b. With the emerging development of Myanmar and its resource surplus, particularly on oil and gas, coupled with its strategic location to bridge the ASEAN countries to India, the study suggests that a cooperation with Myanmar using India's "Look East Policy" is beneficial for both countries in the long run. The study also suggests that India's proactive and positive movement toward a joint gas field development, along with relatively aggressive measures to acquire new fields for gas exploration, can provide India better energy security in terms of having cheaper gas supply. At the same time, India should provide Myanmar with technical knowledge by developing domestic skill sets, and by helping in the energy market reform of Myanmar. India can also help Myanmar in developing its road, rail, and port facilities that can be used as transit channels. This will not only help Myanmar financially but will also help India to explore the ASEAN energy market in a bigger way. Such connectivity between India and Myanmar could result in realising their trade potential.

c. Since resources in the ASEAN and East Asian countries are abundant but unevenly distributed, the promotion of energy free trade is seen as vital for their economic growth and energy security. The study on energy product trades suggests that intra-regional ASEAN trade in energy product must be prioritised, and in this case, the first priority among the energy products to be integrated in ASEAN is coal, lignite and peat, and gas—both natural and manufactured—in order to contribute to positive welfare impacts on the ASEAN society. Therefore, to realise the full potential of these resources for the ASEAN and East Asian countries, establishing the “ASEAN Coal and Gas Community” needs to be seriously considered.

d. The study on EMI using gravity model of trade in the EAS region demonstrates that the increase of bilateral energy trade is mainly due to the increase in trade potential (due to economic growth) rather than trade efficiency (due to institutional reform). Therefore, the study sees a large room for improvement in the institutional reforms in order to facilitate the trade of energy and energy-related products in the region. It further notes and recommends that energy trade outside of the EAS region provides an important complement to the intra-regional trade.

Power Connectivity-related Policy Recommendations

e. The study on power connectivity for the ASEAN Power Grid plus China and India (APG+2) demonstrates that if an 80% trade shall be allowed, there will be US$12.1 billion of net saving from system costs. In this sense, to ensure that financial viability becomes a reality, policies should be designed and implemented to relieve non-financial barriers to keep investment risks low and, therefore, ensure financial viability. The study also recommends that there is a need to optimize the routes and timing of the power interconnectivity in the region to reduce system costs, and enhance the commercial and financial viability of the connectivity projects.

f. The study on power connectivity in the GMS took a close look into the power trade and development in the future. In the 2030 scenario where GMS could realise its large potential of hydropower capacity, such development will result in both economic and environmental benefits. The region at large will benefit by about US$40 billion, and gain further by cutting down on CO_2 emission by almost 70 metric tons/year. This study suggests that in order to attract more investments while reducing risk in hydropower development, there is a need to refine the investment cost, and the hydrological data acquisition and mitigation of social/environmental impact of these hydropower projects. Inter-government joint investments and international financial institutions (IFIs) can play important roles in fostering the necessary legal and legislative framework and in ensuring a continuous investment flow into the energy export market. Some lessons can be learned from the Lao PDR in its hydropower development. A clear basis for regional market rules comprising agreed rules and agreed indicative planning (priority) of interconnection among GMS countries should be in place.

g. The reform of China's electricity sector offers some experiences for electricity market integration. For a long time, China's electricity sector has been heavily regulated with the state-owned company, State Power Corporation (SPC), being the dominant player in the market. Since reform started in 2002, China has made significant progress in institutional development in the electricity sector. However, three government bodies—the National Development and Reform Commission (NDRC), National Energy Administration (NEA), and State-owned Asset Supervision and Administration Commission (SASAC)—are all involved to some extent in the affairs of the electricity sector. This situation calls for the establishment of a single, independent regulatory institution in the sector. The physical interconnection of several grids in China is completed but is yet to be converted into a force for electricity market integration. The Chinese electricity market is still fragmented. Cross-regional as well as cross-border power transmission is not guided by the market. Therefore, China will need to speed up the reform for an integrated electricity market that could offer potential benefits such as price stability, better response to emergencies, and a more efficient use of resources.

Price Mechanism-related Policy Recommendations

h. The continued study on the measurement of EMI is a useful mechanism for checking if policy components are being improved. Results show that significant progress has been made for the EMI in the EAS region, though there are cross-country disparities in different areas. Further efforts toward EMI in general should focus on liberalising national markets, followed by phasing out of fossil fuel subsidies, and liberalising investment regime. Certain countries that are lagging behind in EMI may have to catch up and learn from their past experience or from others and put more emphasis on their relatively weak dimensions.

i. The review on the feed-in tariff policy in Malaysia, the Philippines, and Thailand offers important lessons learned for other EAS countries to look into. In Malaysia, the government deliberately exempted lower-income households in the coverage of the feed-in tariff levy. Domestic customers with consumption levels below 300 kilowatt-hour (kWh) per month are not required to contribute to the RE Fund. In the case of the Philippines, no special considerations for lower-income households were included in the feed-in tariff rules and guidelines. Basically, the only consideration that is relevant to the feed-in tariff allowance payments is the lifeline rate. Philippine households that consume within or less than the defined lifeline rate are exempted from paying all other utility charges. Thailand has also a similar uniform charge rate for feed-in adder. The adder obligations are being passed on to consumers via the fuel adjustment tariff (Ft) charge. With the regulatory reset in July 2011, the adder charges were moved to the base tariff and only the adder charges from this period to the present are reflected in the Ft charge. For 2013, the estimated equivalent uniform adder charge is THB 0.053 per kWh. Thus, a key policy recommendation is for countries to implement their own feed-in tariff policies with their own designs to protect the poor who need access to commercial electricity.

j. The study on energy intensity, in association with income level in each of the EAS countries, offers encouragement for countries to pursue policies in curbing the growth of energy intensity. The findings suggest that it does not matter what level of per capita income a country has; as long as the country has the right policies in place, it can reduce energy intensity. Therefore, it is very important for each country to revisit its energy efficiency policies in different sectors to ensure that structural changes in the economy will maintain energy efficiency as the core of its policy. Thus, a few countries in the EAS region may need to speed up their policies to reduce energy intensity so that in the long run, this could bring in the negative growth of energy intensity. The study suggests that aggressive energy efficiency policies will need to be considered by countries with positive energy intensity.

k. The study on oil price shocks offers some suggestion for the EMI. The lead author suggests that EMI can offer benefits in terms of risk sharing and optimal resource allocation.

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CHAPTER 2
Energy Commodity Trading in Singapore

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Singapore has transformed its economy into an energy trading hub within a few decades. Such transformation was made possible by a strong government drive, private sector participation, and its natural geographical location as one comparative advantage. Institutional effort was another key driver for the successful transformation. Being an energy trading hub, Singapore is able to help create one price prevail across the markets. As a trading hub, Singapore not only physically connects various markets but also makes the law of one price prevail in the markets thereby promoting energy market integration.

Keywords: energy trading, engine of growth, oil industry, law of one price, energy market integration

JEL Classifications: Q40, Q48

Introduction

From 1961 to 1973, Singapore has successfully built five refineries. After establishing a free trade zone (FTZ) in 1969, Singapore has promoted free trade for petroleum and petroleum products in the FTZ. Singapore is often called as “Houston in Asia” (Doshi, 1989). Although Singapore does not have crude oil reserves, it has managed to be one of the oil hubs in the world following Houston in the United States (US) and Rotterdam in the Netherlands. This success has been attributed to prevailing economic and political conditions in Singapore. The newly independent nation, surrounded by Islam nations such as Indonesia and Malaysia, had a strong demand for energy products mainly from post-war economic drive in Japan and the war in Viet Nam, and its stable political regime provided a safe haven for Chinese investors overseas (Horsnell, 1997). Refinery capacity and oil products show the importance of Singapore in the world oil market. The share of oil-related industries in its economy exhibits the importance of the industry to Singapore’s economy.

Singapore’s economy can be characterized as a strong interventionist and planned one (Huff, 1994). A growth accounting analysis shows that Singapore has been heavily dependent on energy or oil for the first two decades since its independence in 1965 (MTI, 2001, 2002a and 2002b). After two oil shocks and the recession in 1985, the oil industry in Singapore has shrunk but its contribution to the economy has been stable at around 1percent of value-added.

As a strategy of reviving the oil or energy industry in Singapore, the Approved Oil Trader (AOT) was introduced in 1989 and Approved International Trader (AIT) in 1990. The two programs were combined in 2001 and renamed as Global Trader Programme (GTP). GTP has evolved and is considered a main factor in transforming Singapore into a trading hub, not only for energy but also for other commodities.

This chapter reviews the status of oil and oil products that are exported and imported in Singapore. It analyses how oil and energy have contributed to the economic growth of Singapore and examines what factors attributed to making Singapore an energy and commodity trading hub. Along with the review and analysis, it draws some lessons learned from the success story. This paper is structured as follows: Section 2 reviews the characteristics of Singapore's economy, Section 3 presents Singapore as an oil center, Section 4 explores how institutional factors helped Singapore became an energy and commodity trading hub, and Section 5 examines what implications can be drawn for energy market integration (EMI) from the case of Singapore. Section 6 concludes this paper.

Characteristics of the Singapore Economy

The main characteristic of the Singapore economy is the role of the government. The government appears to intervene in a wide range of economic activity and planning. The Singapore economy is considered a decisive departure from the market mechanism and a domestically managed regime. Its manufacturing sector is export-oriented and is controlled by the government. However, the economy shows that planning and the market appear as a creative partnership. The other key characteristics are the government-directed labour market, state-owned enterprises, and government-forced saving. The government-forced saving appears to help infrastructure and housing provision, and draw private sector investment and promote capital accumulation. Along with these, the government carried out plans for manufacturing development and made Singapore specialised in financial and business services. The successful transformation is also attributed to the utilisation of the country's natural comparative advantage of geographical location and the augmentation of this particular advantage (Huff, 1994).

A growth accounting analysis by the government that focused on the supply-side of the economy showed that foreign talents with employment pass and work permit were an integral building block for the economic success and contributed 41 percent of GDP in the 1990s (MTI, 2001). A demand-side analysis by the government identified four engines of economic growth—the US economy, worldwide semiconductor sales, ASEAN-2 countries (combined GDP of Indonesia and Malaysia), and domestic construction works (MTI, 2002a). Another demand-side analysis shows how Singapore's engine of growth has changed since 1965 (MTI, 2002b).

Among others, trade is clearly shown as an 'engine of growth' in a demand-side analysis (MTI, 2002a and 2002b). Since its independence in 1965, 'the oil sector' has been an engine of growth and has contributed 1.1 percentage points to economic growth from 1965 to 1974, and 50 percent of domestic exports by commodity during the period. From 1975 to 1984, however, it has contributed a mere 0.4 percentage points to economic growth but still 47.6 percent of domestic exports by commodity during the period. This reflected the shrunk of the oil sector in Singapore due to external reasons after two oil shocks. From 1985 to 1991, the oil sector was no longer considered an engine of growth due mainly to the collapse of commodity prices, including oil, and its contribution to domestic exports by commodity has fallen to 26.1 percent. The oil sector has petered out from 1992 to 2001 and its contribution to domestic exports by commodity is just 18.3 percent. These changes present the structural shifts in the economy. Statistics show that the oil sector has contributed about 20 percent of domestic exports by commodity, 1–2 percent of value-added, and close to 1 percent of employment since 2002 (Department of Statistics, 2013).

Singapore as an Oil Center

Singapore was a strategic entrepôt even before its independence in 1965. At the time the oil sector was not much controlled by the government, the government did not block the oil sector from performing its business nor provided any incentive. The Shell oil company developed a distribution center of oil in Singapore in the 1860s and further added the functions of storage, bunkering, and blending (Horsnell, 1997). What was missing in the supply chain of oil then was refining. After independence, Singapore noted the missing channel in the supply chain of oil and invested in developing oil refineries. With this investment, the country emerged as an oil refining center with five refineries built within 12 years. The 12 year-drive for attracting foreign investments in oil refineries was done by mainly offering tax-free operations for the first five years. Following the initial success in building an oil refinery industry and the sustained economic growth, Singapore faced a downturn and fluctuation of the refinery industry.

Fluctuations of the Singapore Refinery Industry

The favorable operation terms, including the tax-free operations for the first five years, were the key drivers for building five refineries in Singapore. There were other factors, however, that helped Singapore build the oil refinery industry. *First*, the threat of nationalising asset in Asia after the World War II made Singapore an oasis in Southeast Asia in the sea of Islam. *Second,* the economic boom in Japan after the World War II made Singapore the right place for refining crude oil for Japan, which asked Singapore to refine the crude oil that Japan imported from the Middle East. *Third*, the Viet Nam war provided Singapore the opportunity to be used as a channel for the US to supply oil and oil products to its troops. This accounted for over 20 percent of oil exports from Singapore. *Fourth,* Singapore has been an entrepôt since the 1890s and this helped Singapore acquire a comparative advantage in transporting oil and oil products (Horsnell, 1997).

The two oil shocks in the 1970s had negatively affected the world economy. Singapore was not an exception. The first oil shock changed the oil industry in Singapore as the shock made supply security a top priority for oil-importing countries. Japan withdrew its refining contracts from Singapore, which led to a huge cut in the demand for oil products. With this, Singapore's role in supplying oil products was diminished, but by then, it has already emerged as an oil trading hub in Asia and at the stage of transforming itself into a financial and business hub.

Growth of Trading in Singapore

In the mid-1980s, the trading of oil products was centered on Singapore, while crude oil trading took place in Tokyo. But Tokyo has given way to Singapore as Tokyo was an expensive place for doing business, has tight liquidity, and is considered high risk, in addition to the Japanese government's disenchantment with oil trading. All these worked as a push factor for Singapore to emerge as a center for physical oil trading (Horsnell, 1997).

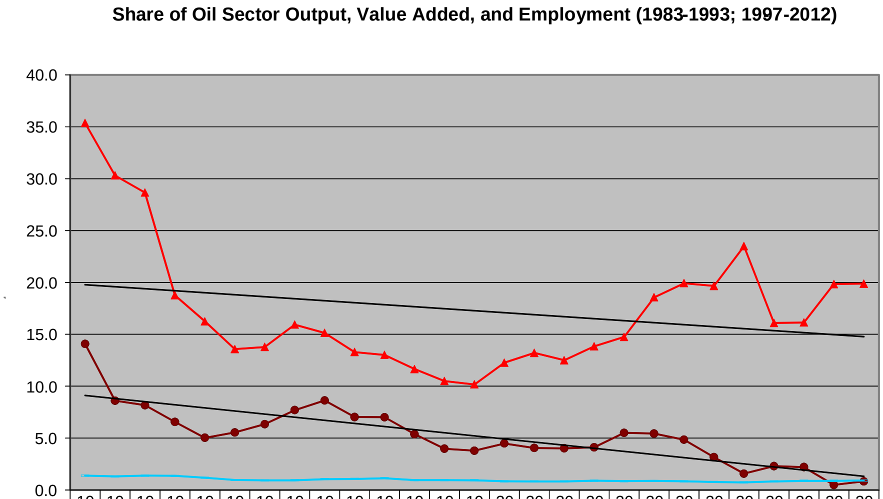
Upon noticing a shrinking trend in the oil refinery sector, Singapore envisioned an oil trading center and introduced the AOT scheme. The scheme gave a concessionary a 10 percent tax rate on trading activity, which worked as a strong pull factor, attracting many trading firms to open their offices in Singapore. In addition, Singapore offered lower operation costs. Another factor that attracted firms to Singapore was its favourable time zone position. The operation hours of Singapore’s exchange floor overlap with those of the US and Europe. By the time the US exchange floor closes, the exchange floor in Singapore opens, and by the time the Singapore exchange floor closes, the European exchange floor opens. Singapore can be connected throughout 24 hours. It also provides better living conditions and language options compared to Japan. Altogether, these factors helped Singapore become an oil trading hub.

Oil in Singapore Economy

There were several engines of growth in Singapore and these changed over time (MTI, 2002b). Oil was one of the growth engines in the early days (Horsnell, 1997; Ng, 2012) and is still contributing about 10 percent of the total trade. The oil sector has helped in the successful transition of the Singapore economy into petrochemical and electronics industry. Unlike in the trade of goods and services, there is not much bilateral trade between Singapore and its trading partners due to the unique characteristics of oil and oil products trade. Singapore imports crude oil from various countries mainly from Middle Eastern countries and Australia, Viet Nam, and the Philippines in the region; refines crude oil at its integrated refinery; and exports oil products to Asian countries such as Hong Kong, Japan, and China, and to Panama and Liberia.

Figure 2.1 presents how the oil sector in Singapore has contributed to the economy from 1983 to 1993 and from 1997 to 2012. As stated earlier, the oil sector’s contribution to the economy in the early years was higher than 2 percentage points in economic growth. This contribution has decreased to around 1 percent of value-added. A decreasing trend in the shares of manufactured output, value-added, and employment is shown over time. Increasing oil prices mainly contributed to the increasing trend in output, but value-added or profitability (i.e., refinery margins) have declined mainly due to severe competition, and employment was stable or decreasing due to the integration of refinery and a productivity improvement that resulted in not creating much new employment. This also reflects that the Singapore economy has shifted to non-oil-based economy although the contribution of the oil sector is not negligible.

Figure 2.1: Contribution of the Oil Sector to the Singapore Economy



	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Output	35.	30.	28.	18.	16.	13.	13.	15.	15.	13.	13.	11.	10.	10.	12.	13.	12.	13.	14.	18.	19.	19.	23.	16.	16.	19.	19.
Value Added	14.	8.6	8.2	6.6	5.0	5.5	6.3	7.7	8.6	7.0	7.0	5.4	4.0	3.8	4.5	4.0	4.0	4.1	5.5	5.4	4.8	3.2	1.6	2.3	2.2	0.5	0.8
Employment	1.4	1.3	1.4	1.4	1.2	1.0	0.9	0.9	1.0	1.1	1.1	0.9	0.9	0.9	0.8	0.8	0.8	0.9	0.9	0.9	0.8	0.8	0.7	0.8	0.9	0.9	0.9

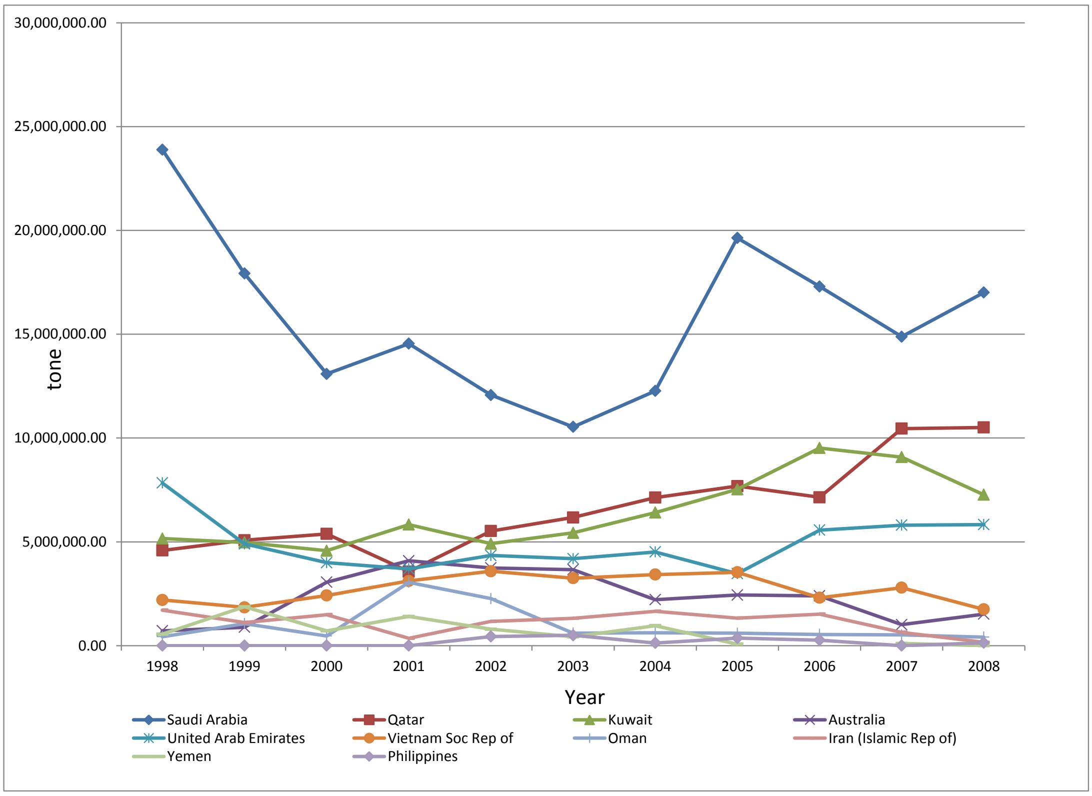
YEAR

Output
Value Added
Employment
Linear (Output)

Source: Statistics of Singapore, *Statistic Yearbook of Singapore*, 1997 - 2012 issues.

Figure 2.2 presents the amount of crude oil that Singapore imports. As of 2008, 7 of the top 10 exporting countries are in the Middle East, and Saudi Arabia is the largest exporting country. Australia is the fourth largest exporting country, and Viet Nam and the Philippines are the Asian countries from which Singapore imports crude oil.

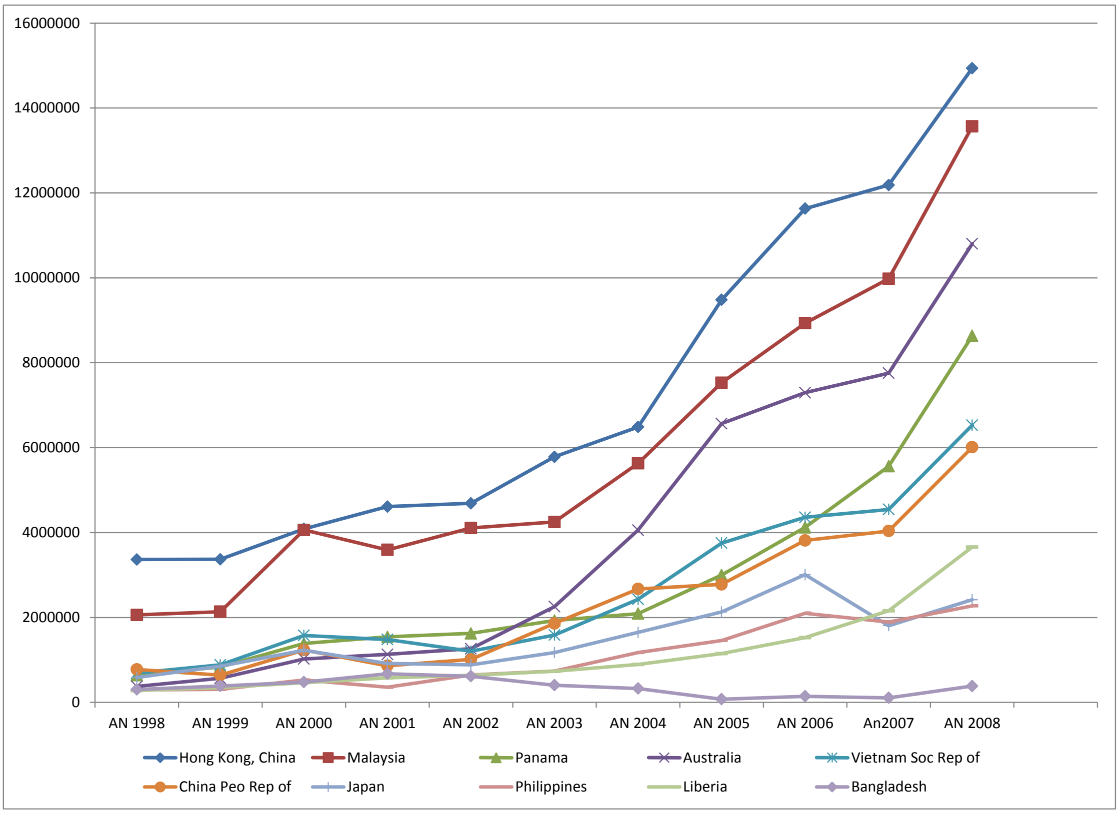
Figure 2.2: Ten Largest Petroleum Crude-Exporting Countries



Source: Statistics of Singapore, *Statistic Yearbook of Singapore*, 1998-2009, various issues.

Singapore, as an oil refining hub in Asia, imports crude oil from Middle Eastern countries and exports oil products. Figure 2.3 presents the countries to which Singapore exports most of its oil products. As of 2008, the largest volume of oil products is exported to Hong Kong, followed by Malaysia. Australia, China, and Japan are also among the top 10 largest importing countries. Panama is the fourth largest importing country. Singapore imports crude oil from Viet Nam and the Philippines and exports oil products to the two countries. Liberia is another country in the top 10 largest oil product-importing countries.

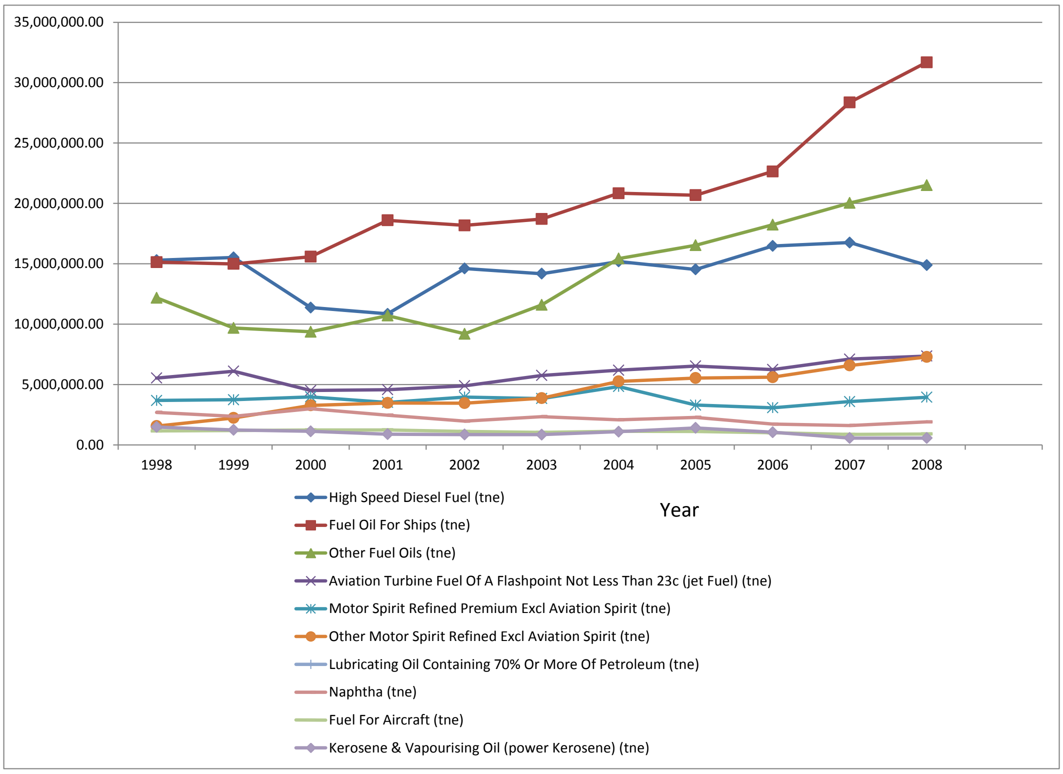
Figure 2.3: Top 10 Oil Product-Importing Countries



Source: Statistics of Singapore, *Statistic Yearbook of Singapore*, 1998-2009, various issues.

Singapore exports various oil products to many countries. Figure 2.4 shows the top 10 largest oil products exported from Singapore as of 2008. They are (1) high-speed diesel fuel, (2) fuel oil for ships, (3) other fuel oil, (4) aviation turbine fuel of a flashpoint not less than 23c (jet fuel), (5) motor spirit refined premium excluding aviation spirit, (6) other motor spirit refined excluding aviation spirit, (7) lubricating oil containing 70 percent or more of petroleum, (8) naphtha, 9) fuel for aircraft, and 10) kerosene and vaporising oil (power kerosene). The oil products that Singapore exports most are the fuels for shipping, aviation, and transportation. This reflects the fact that Singapore is an entrepôt and a shipping and aviation hub, and has augmented its natural comparative advantage to achieve its economic success. Singapore is located in the middle of the trade route between East and West and has a deep port—which are geographical competitiveness that may not be replicated by any other country (Huff, 1994). Together with institutional support, good government planning, and persistent drive, these geographical competitiveness helped Singapore become an oil trading hub in the region.

Figure 2.4: Ten Largest Oil Product Exports from Singapore



Source: Statistics of Singapore, *Statistic Yearbook of Singapore*, 1998-2009, various issues.

Some lessons can be drawn from the success story of Singapore's transformation from an oil distributing center into an oil trading hub and the achievement of its economic growth by creating and promoting the oil industry. The first lesson learned is the positive role of government in economic development. *Second*, it highlights the importance of investment in infrastructure and education. *Third*, it shows how successful economic planning can be undertaken—where the control over key macroeconomic variables was well managed and the coordination of public sector investment and attracting private investment was well implemented. *Fourth*, it shows the weaknesses and limits of government control where little delivery of technological gains in manufacturing was made.

Institutional Factors that Made Singapore an Oil Trading Hub

Along with the natural comparative advantage and its augmented competitive edge, a few institutional factors helped Singapore became an oil trading hub within a few decades. Among others, the AOT and AIT schemes, and later the Global Trader Programme (GTP), and the combined schemes of AOT and AIT were the main drivers.

AOT, which was for oil trading, was introduced in 1989 while AIT, which aimed for the trading of commodities other than oil, was introduced in 1990. These two schemes were merged in 2001 and became GTP under the auspice of the International Enterprise Singapore (IE Singapore), a government statutory. GTP had more than 270 international trading companies in Singapore and covers oil and carbon.

There are many merits of being under GTP but the most notable is a concessionary tax rate on qualifying incomes; the tax rates range from 5 percent to 10 percent. GTP encourages global trading companies to use Singapore as their regional or global base to conduct activities along the total trade value-added chain from procurement to distribution, in order to expand into the region and beyond.

The list of qualified products and commodities, which are to be reviewed periodically, includes petroleum and petroleum products, agricultural commodities and bulk edible products, building and industrial materials, consumer products, industrial products, machinery components, metals and minerals, and electronic and electrical products. The qualified transactions are principal trades with offshore parties or other companies with GTP status on both the buy and sell legs of the transaction. The physical trades that qualify are for offshore, goods does not pass through Singapore; for transhipment, transferring cargo from one transport mode to another and for re-export, only non-value added portion of re-export trade.

When applying for GTP status, an initial, non-renewable three-year GTP status is granted by IE Singapore. If during this period the company establishes its global trading network and demonstrates sustainable growth projections, with Singapore as its base, it can apply for the renewable five-year GTP status. GTP has three minimum criteria. *First,* there must be substantial physical offshore trading turnover on a principal basis. *Second*, there must be significant local business spending attributable to trading activities in Singapore. *Third*, there must be employment of professional traders in Singapore. The other considerations are (1) the company should have an overall business plan and economic contribution to Singapore; (2) it uses banking and financial services available in Singapore; (3) it uses other Singapore-based services such as trade and logistics, arbitration, and ancillary; (4) it should contribute to manpower training and development of trading expertise in Singapore.

Implications for EMI

Market integration could mean the convergence to one price—"the law of one price" (Grossman, 1976; De Vany and Walls, 1999). Energy trading would help the one price be possible for energy commodities. Singapore, as the established oil and oil products trading hub in the region, can expand its scope of trading to other energy commodities, such as natural gas and electricity, and help one price for oil, oil products, or other energy commodities—such as natural gas and electricity—to prevail in the region by facilitating the trading of such energy commodities in the integrated energy market where buyers can find sellers and vice versa. Unless an energy market is integrated, matching buyers and sellers would be very costly if not impossible. The one price can be achieved when all parties involved are free to trade. Singapore can promote trading of not only oil and oil products but also of other commodities ranging from agricultural products to metals, electronics, and carbon. Such trading makes all the different prices converge to a single price. As the literature suggests, "the law of one price" is the evidence of market integration. Price convergence will make "the law of one price" prevail in the market. With an integrated market, there are more buyers and sellers and they could find better prices, which eventually makes one price prevail for the buyers and the sellers in the market. Both buyers and sellers find the right trading partner and they would benefit from participating in the integrated energy market, which could further promote and strengthen the EMI.

Unless an energy market is integrated, a buyer in one market is not able to get energy from a seller in the other market although the seller has a surplus. This translates into loss to both the buyer and the seller—the buyer must pay a higher price or will not get the energy it needs while the seller must give up the gains from selling its surplus in energy. Two separate markets cannot accrue such potential benefits from the integrated energy market. The working energy trading hub in the region would have countries in the ASEAN region see the price of energy goods traded and free to choose the better price so that it helps the energy price converge to a single price. Having an energy trading hub and linking it to other countries in the region helps each country quote the price determined in the trading hub and would eventually make a single price prevail in the market. By doing so the market integration could be completed. An energy trading hub would accelerate the EMI.

Conclusion

Singapore presents an interesting case where the government's intervention in planning and developing its economy helped in achieving an economic success. Along with its geographical location as a comparative advantage, Singapore provided much institutional effort in successfully transforming its position as just a distribution center of oil into an oil trading hub. At the center of these efforts are the AOT and AIT schemes, which later became the GTP. This promoted not only trading of oil and oil products but also the trading of other commodities, including carbon. The energy trading hub would facilitate the trading of energy commodities and make the price for the traded commodities converge to a single price by decreasing or eliminating the price gap between countries. This in turn would accelerate EMI by holding the law of single price for energy commodities in the market.

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CHAPTER 3

Energy Trade Practices in India: Review of Tariff and Non-Tariff Barriers in Relation to ASEAN

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The EAS region has several factors---e.g., geographical proximity, gaps in energy supply versus demand, and different socio-economic conditions---that are conducive to energy cooperation between India and its neighbours. Thus, this study focuses on India's energy trade with other countries in the East Asia Summit (EAS) region, especially the Association of South East Asian Nations (ASEAN), its barriers and limitations. It suggests that India has the capacity to boost its energy trade in both domestic and international markets. An eventual integration with the ASEAN and EAS region holds great promise for India's own economic development. At present, however, India has a weak energy trade network, which should be strengthened so as to optimally utilise energy resources. Existing barriers, both tariff and non-tariff, are hindering this process. India needs to reform the bilateral relations with every member-nation of the ASEAN in terms of the requirements of that particular country and that of India. This study further looks at the various obstacles in the energy sector that hinder trade between India and ASEAN countries and suggests possible steps for removing these.

JEL Classification: F13, Q4, Q40, Q41, Q42, Q48, Q49

Introduction

India’s economic policies after 1947, the so-called post-independence years, were socialist in nature. Attempts to liberalise the economy in 1966 and in 1985 failed, and the actual economic liberalisation began only in 1991, after the economic crisis in India. The downfall of the economy was attributed to a high fiscal deficit of 12.7 percent in 1990-1991 and to political instability. The situation was further aggravated by the crisis in the Gulf (Middle East) countries, wherein a steep rise in prices of oil and consequently, of petroleum imports into India, became very expensive. Foreign remittances from migrant Indian workers in these countries also declined, and several creditors and investors pulled out their resources from India (Cerra and Saxena, 2000). The Soviet Union, India’s largest export market, weakened due to the crises in the Gulf; thus, exports too declined. All these factors resulted in the devaluation of the Indian currency.

The government of India was compelled to restructure its economic policy not only to revive its economic growth, but also to tackle widespread poverty in the country. The economic liberalisation initiated in 1991 brought about a total shift to a more open economy with greater reliance upon market forces; a dynamic private sector, including foreign investment; a restructuring of the government's role; a phase out of import licensing; and reduction of import duties (Ahluwalia, 2002). In India, the Foreign Trade (Development and Regulation) Act of 1992 provides for the expansion and regulation of foreign trade and implementation of the export-import policy. Accordingly, the Ministry of Commerce and Industry promotes and regulates foreign trade and also releases notifications on trade policies on a regular basis.

Gradually, India has shifted from conservative trade approaches to more progressive policies that encourage export-led growth, thus improving efficiency and competitiveness of industries. Globalisation of the Indian economy became the guiding force behind the formulation of trade policies. Reform measures introduced in the subsequent policies focused on liberalisation, openness, and transparency. They promoted a trade-friendly environment by simplifying the procedures for doing business.

In the first quarter of 2012, the Indian economy grew by 5.3 percent, the lowest in almost a decade. With surging trade and budget deficits, and a depreciating currency, there is widespread concern over whether India would see the return of a “1991-like crisis” (Financial Times [FT], 2012). To revive its economy and thus create an efficient and financially stable energy sector, India must maintain further economic growth and reduce any negative impact on its public finance. This needs an accelerated transition of the energy sector based on a market economy.

India's social and economic development has slowed down due to severe energy shortage in the fuel sector, including coal, gas, oil and uranium. Its declining domestic production further requires more energy to be imported. India imports crude oil, coal, and gas but because of the disparity between domestic and international prices for these fuels, the volume of actual fuels imported may be less than the volume required to meet the shortage. Moreover, an increasing fuel import has negative financial implications on the economy. Thus, India has to have a well-functioning energy market---i.e., a system where the national energy demand can be met by timely and sustainable investments and where business entities operating in the energy market are commercially viable. Energy policies in India have been designed to address the country’s growing energy deficit and to focus on developing alternative sources of energy, particularly nuclear, solar, and wind energy.

Energy cooperation between India and countries of the Association of South East Asian Nations (ASEAN) needs to be accelerated. After all, several factors across these countries---e.g., geographical proximity; imbalances in distribution between energy resources and demand; and differences in economic, social and energy development stages---justify why forging energy trade relations makes sense. Each country in the region has some comparative advantage that can be harnessed and mutually benefit its energy trade partners. Currently, India’s weak energy trade network needs to be strengthened if it were to optimally utilise and take full advantage of its energy resources.

This paper reviews the energy sector in India, focusing on the energy trade and its barriers and limitations and on the promotion of energy trade between

India and other countries, particularly the ASEAN members. It suggests that India has the capacity to boost its energy trade in both domestic and international markets.

Energy Sector in India: An Overview

India’s total primary energy consumption from crude oil (29.45%), natural gas (7.7%), coal (54.5%), nuclear energy (1.26%), hydro electricity (5.0%), wind power, biomass electricity, and solar power was 595 million tonnes of oil equivalent (Mtoe) in the year 2013. The net imports included about 144.3 Mtoe of crude oil; 16 Mtoe of liquefied natural gas (LNG); and, 95 Mtoe of coal---a total of 255.3 Mtoe of primary energy equivalent to 42.9 percent of the total primary energy consumption (BP, 2014).

About 70 percent of India’s electricity generation capacity is from fossil fuels, of which coal accounts for 40 percent. This is followed by crude oil and natural gas at 24 percent and 6 percent, respectively. India is largely dependent on fossil fuel imports for its energy demands. By 2030, India's dependence on energy imports is expected to exceed 53 percent of the country's total energy consumption.

The growth of electricity generation in India has been hindered by domestic coal shortages and, as a consequence, India's coal imports for electricity generation have risen (IEA, 2012). Given such ever-increasing energy demand coupled by restricted domestic fuel reserves, India set up extensive plans to develop the renewable and nuclear power industries. There are four main types of energy in India: *thermal* (coal, gas, oil), *hydro (major)*, *renewable* (small hydro, wind, and solar), and *nuclear energy*. Table 3.1 provides details of the installed capacity of energy utilities in India as of December 2013.

Table 3.1: Installed Capacity (MW) of Energy Utilities in India

Type	Source	Total Capacity	Percentage
Thermal	**Total**	**159,793.99**	**68.19**
	Coal	138,213.39	58.75
	Gas	20,380.85	8.92
	Oil	1,199.75	0.52
Hydro (Conventional)	Hydroelectricity	**39,893.40**	**17.39**
Renewable Energy Sources (RES)	SHP, BG, BP, U&I*; Wind & Solar Energy	**29,462.55**	**12.33**
Nuclear	Nuclear	**4780.00**	**2.09**
Total		**2,33929.94**	**100.00**

Note: *SHP= Small Hydro Project; BG= Biomass Gasifier; BP= Biomass Power; U & I=Urban and Industrial Waste Power.
Source: Central Electricity Authority, 2014.

The power sector in India is under the Ministry of Power (MoP) and has three major segments: generation, transmission, and distribution. Power Generation consists of three sectors: state, central, and private. State-level corporations consist of State Electricity Boards (SEBs), which are formed in all the states and at present constitute about 38.83 percent of overall power generation with an installed capacity of 90,836.70 MW. The central sector, also known as Public Sector Undertakings (PSUs), accounts for 32.53 percent of the installed capacity (76,095.30 MW). Such major PSUs include the National Hydroelectric Power Corporation Limited (NHPC Ltd), National Thermal Power Corporation Limited (NTPC Ltd), and Nuclear Power Corporation of India (NPCIL). The private-sector enterprises comprise 28.64 percent (66,997.94 MW) of the total installed capacity. Table 3.2 shows the sector-wise distribution of energy in India (as of December 2013).

Table 3.2: Sector-Wise Distribution of Energy Utilities in India

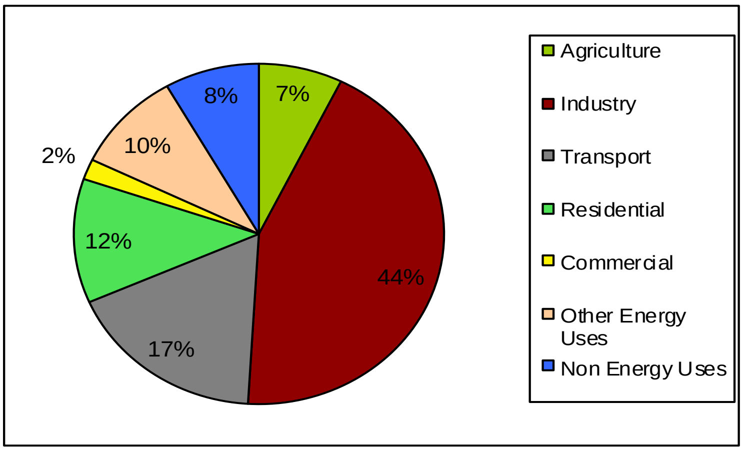
Sector	Total Capacity (MW)	Percentage
State Sector	90,836.70	38.83
Central Sector	76,095.30	32.53
Private Sector	66,997.94	28.64
Total	**2,33929.94**	**100.00**

Source: Central Electricity Authority, 2014.

Figure 3.1 shows the India's sector-wise energy consumption in 2012-2013. Industry garnered the main share (44%), followed by the Transport sector (17%); Residential sector (12%); Other Energy Uses (10%); Non-Energy Uses (8%); and Agriculture sector (7%). The Commercial sector has the least share at 2 percent. On the other hand, Figure 3.2 illustrates the energy consumption of India in 2012-2013. The highest share in India is that of coal (53%), followed by oil (30.45%). On the other hand, the world energy consumption shows a reversed trend as its major share is that of oil (33.11%), followed by coal at 30 percent (BP, 2013).

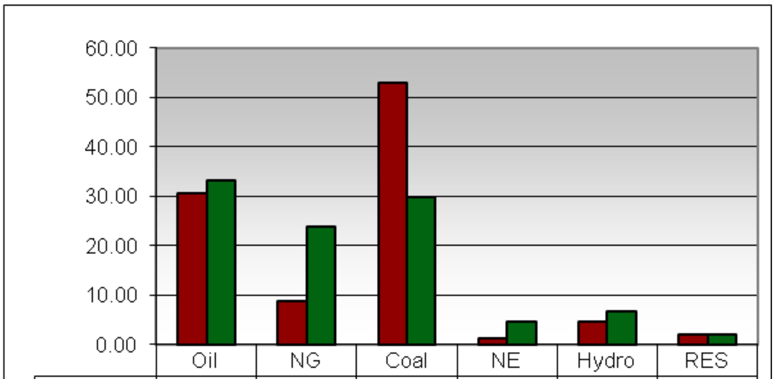
In terms of total energy consumption in the world, India is the third largest consumer at 774 Mtoe, after China at 2,713 Mtoe, and the United States at 2,152 Mtoe (Enerdata, 2013).

Figure 3.1: Sector-Wise Energy Consumption in India (%)



Source: TERI, 2013.

Figure 3.2: Energy Consumption: India v/s World (%)



	Oil	NG	Coal	NE	Hydro	RES
INDIA	30.45	8.71	52.94	1.33	4.65	1.93
WORLD	33.11	23.94	29.90	4.49	6.66	1.90

Source: BP, 2013.

Energy Sources

India's largest energy source is coal, followed by petroleum and traditional biomass such as burning firewood and waste. Its energy policy aims to ensure that the energy sources are adequate to meet the demands of its fast growing economy. However, factors such as subsidies, rising dependency on imports, and poor reforms in this sector impede India's efforts to meet the energy demand (Energy Information Administration [EIA], 2013).

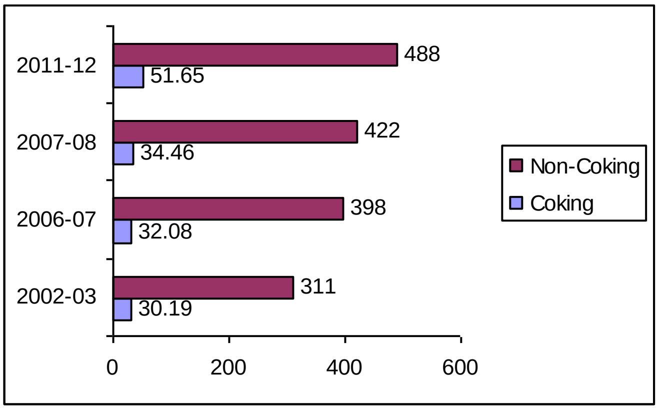
Coal

India is the fourth largest coal producer in the world after China, the United States, and Australia. Due to continued increase in investments, its production has grown from about 70 million tonnes (MT) in the early 1970s to 557 MT in 2012-2013 (BP, 2012). More than 991 of India's coal deposits are found in the eastern and south central parts of the country---in particular, in the states of Jharkhand, Odisha, Chhattisgarh, West Bengal, Andhra Pradesh, Maharashtra, and Madhya Pradesh. The estimated reserves of coal were around 293.5 billion tonnes in 2012. Most of the coal production in India comes from open cast mines (88%) while underground mining accounts for the rest (12%) of the national output (Ministry of Coal, 2013).

Generally, coal is classified in terms of certain chemical (ash, moisture, and volatile matters) and physical (caking index, coke type, and swelling index) parameters. In India, coal is broadly classified into two types: coking and non-coking. India has the fifth largest coal reserves in the world. About 88 percent of these are non-coking coal reserves and 12 percent coking. Indian coal is characterised by its high ash (45%) and low sulphur content. The power sector is the largest consumer of coal, followed by the iron and steel, and cement sectors.

Lignite is commonly known as brown coal and is classified as grades A to C on the basis of gross calorific value as per the requirement of the industries. It is considered as an appropriate fuel for power generation especially due to its low ash content (Geological Survey of India [GSI], 2014). Figure 3.3 presents the coal production trend in India from 2002-2012, wherein it can be seen that non-coking coal garners the major share and its production is increasing rapidly to meet the high demand from the power sector.

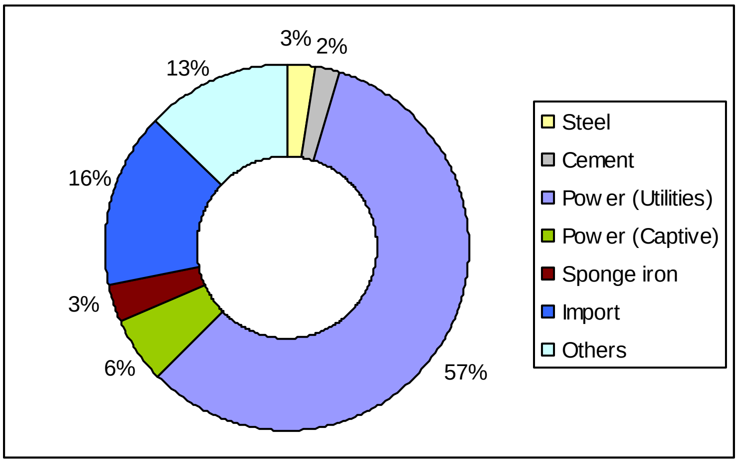
Figure 3.3: Coal Production Trend in India (MT)



Source: GSI, 2014.

More than half (58.75%) of the total installed electricity generation capacity in India’s energy basket is coal based. The demand for coal is projected to reach 980 MT during the 12th Five-Year Plan of the Government of India (2012–2017). Domestic production is expected to rise to 795 MT in the terminal year (2016-2017). Although the demand gap will be met through imports, domestic coal production is slated to grow at an average rate of 8 percent compared to about 4.6 percent during the 11th Five-Year Plan (2007-2012). As the major source of energy consumption in the country, coal contributes about 30 percent of the total domestic consumption. Figure 3.4 shows the sector-wise distribution of coal consumption in India. About 63 percent of the coal in the country is consumed in the power sector, followed by the import sector (16%).

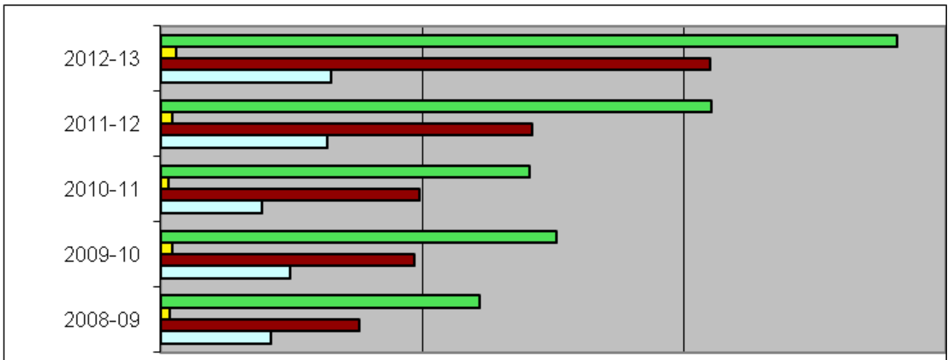
Figure 3.4: Sector-Wise Distribution of Coal Consumption in India (%)



Note: *Others: Includes, jute, bricks, coal for soft coke, colliery, fertilisers and other industries consumption.
Source: Ministry of Coal, 2013.

Although India has the fifth largest coal reserves in the world, its coal sector is one of the most centralised and inefficient. Two state-owned companies; namely, the Coal India Limited (CIL) set up in 1975 and the Singareni Collieries Company (SCCL), have a near-monopoly on production and distribution. There is an increasing gap between demand and supply. On the supply side, India's coal imports have grown by more than 13 percent per year since 2001 (EIA, 2013). Figure 3.5 shows the coal import trend in India by type over the last five years.

Figure 3.5: Coal Imports to India by Type (MT)



	2008-09	2009-10	2010-11	2011-12	2012-13
Total Imports	60.88	75.6	70.4	105.21	140.63
Coke	1.88	2.35	1.49	2.36	3.07
Non-Coking	37.92	48.56	49.43	71.05	105.00
Coking	21.08	24.69	19.48	31.8	32.56

Source: MoC, 2013.

Based on the existing Indian Import policy, consumers themselves can freely import coal under an open general license. Steel Authority of India Limited (SAIL) and other steel-manufacturing units import coking coal, while coal-based power plants import non-coking coal. Main importers of coke include pig-iron manufacturers, iron-and-steel sector consumers using mini-blast furnace, cement plants, captive power plants, sponge iron plants, industrial consumers, and coal traders. India imports majority of its coal from Indonesia and South Africa (thermal coal), and Australia (coking coal). However, new regulatory mechanisms in these countries are driving coal prices up, leading India to now look at importing coal from other countries such as Mozambique.

The overall coal import for the year 2012-2013 was estimated to be 140.63 MT. Despite this increase in production, the existing demand still exceeds the supply. There is a perennial shortage of coal. India exports an insignificant quantity of coal to its neighbouring countries, viz., Bangladesh, Bhutan, and Nepal. Domestically, the development of core infrastructure sectors such as power, steel, and cement are dependent on coal (Ministry of Coal, 2012). Unfortunately, there is no provision for private and foreign investment in coal production. Thus, despite having large coal reserves and a healthy growth in natural gas production over the past two decades, India remains very dependent on imported crude oil (EIA, 2013).

Oil and Natural Gas

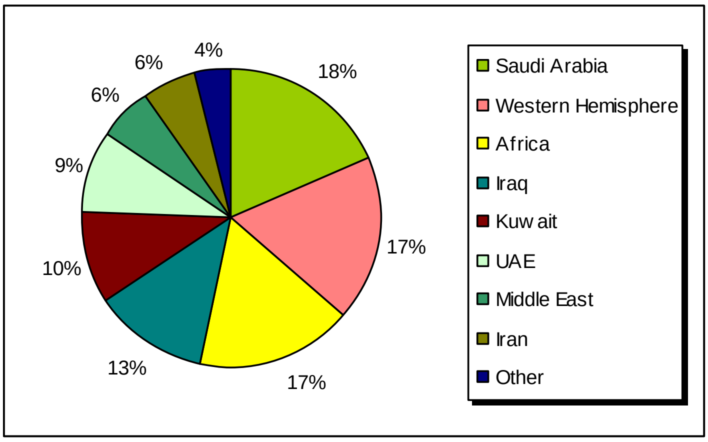
In 2011-2012, India was the fourth largest consumer of crude oil and natural gas in the world after the United States, China, and Russia. The share of crude oil in production and consumption is expected to be 6.7 percent and 23 percent, respectively, by 2021-2022. Petroleum demand in the transport sector is expected to grow rapidly in the coming years as vehicle ownership expands. While India’s domestic energy resource base is substantial, the country relies on imports for a considerable amount of its energy use, particularly for crude petroleum.

Combustible renewables and waste constitute about one-fourth of the Indian energy use. This share includes traditional biomass sources such as firewood and dung, which are used by more than 800 million Indian households for cooking. The estimated reserves of crude oil in India stood at 759.59 MT while that of its natural gas was at 1,330.26 billion cubic metres (Bcm) in 2011-2012. The geographical distribution of crude oil indicates that the maximum reserves are in the Western offshore (44.46%), followed by Assam (22.71%). Meanwhile, the maximum reserves of natural gas come from the Eastern offshore (34.73%), followed by Western offshore (31.62%).

India’s growing dependence on oil imports can be gleaned from the increasing volume of net crude oil imports as well as in the rising share of net crude oil imports in the refinery crude throughput. Imports accounted for 44 percent of crude oil processed (in terms of refinery crude throughput) in 1990, 83 percent in 2010-2011, and 84 percent in 2011-2012.

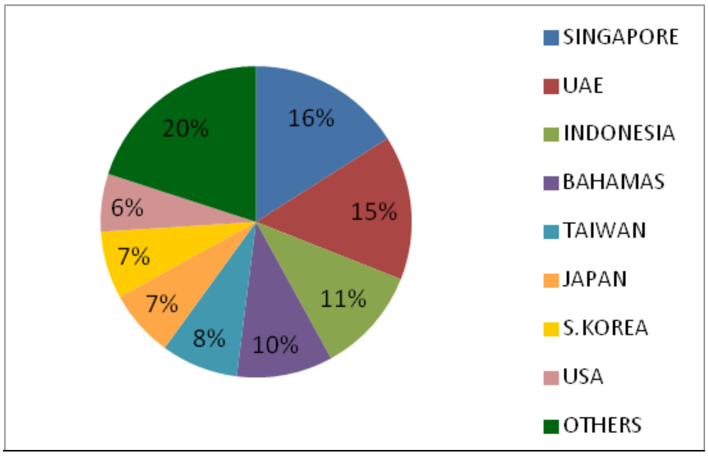
Figure 3.6 shows India's crude oil imports in 2012. Saudi Arabia (18%) is the largest source of India's crude oil imports. The second largest suppliers are Africa---mainly, Nigeria--- (17%), and the Western Hemisphere (17%). While being a net importer of crude oil, India has also become a net exporter of petroleum products (Figure 3.7) such as naphtha, motor gasoline, and distillate fuel oil to the international market, particularly Singapore, the United Arab Emirates, and Indonesia (EIA, 2013).

Figure 3.6: Crude Oil Imports by India in 2012 (%)



Source: EIA, 2013.

Figure 3.7: Export of Oil Products* by India 2012 (%)

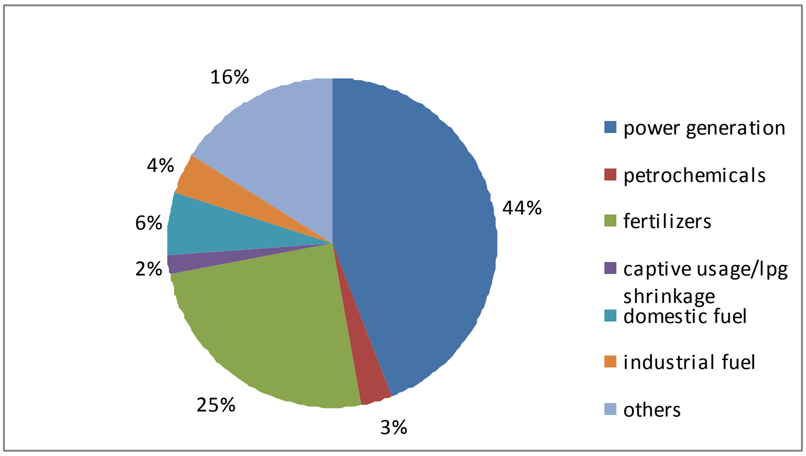


Note:*Oil products -motor fuel, kerosene jet fuel, naphtha
Source: EIA, 2013.

India ranks 11th among the world's natural gas consumers. Ten percent of India's primary energy consumption consists of natural gas (BP, 2012). Note that in 2011-2012, 46.3 Bcm of natural gas was consumed in India, showing a recline of 10 percent over the previous period.

The demand for natural gas has grown at about 6.5 percent during the last decade (Petroleum Planning and Analysis Cell [PPAC], 2012). Several industries such as power generation, fertiliser, and petrochemicals are now opting for natural gas. Although India supplies natural gas for the domestic market, the demand has exceeded the supply. Figure 3.8 shows the sector-wise consumption of natural gas in 2012.

Figure 3.8: Sector-Wise Consumption of Natural Gas in 2012 (In %)



Source: MOSPI, 2014.

In 2011-2012, India imported 13.2 MT of LNG from several countries such as Abu Dhabi, Algeria, Australia, Egypt, Equatorial Guinea, Malaysia, Nigeria, Norway, Oman, Qatar, Trinidad and Tobago, the United States, and Yemen. There are three LNG terminals in the country (Dahej, Hazira and Dabhol). As India imports nearly 80 percent of its crude demand, rising international prices can result in more under-recovered overheads to oil marketing companies.

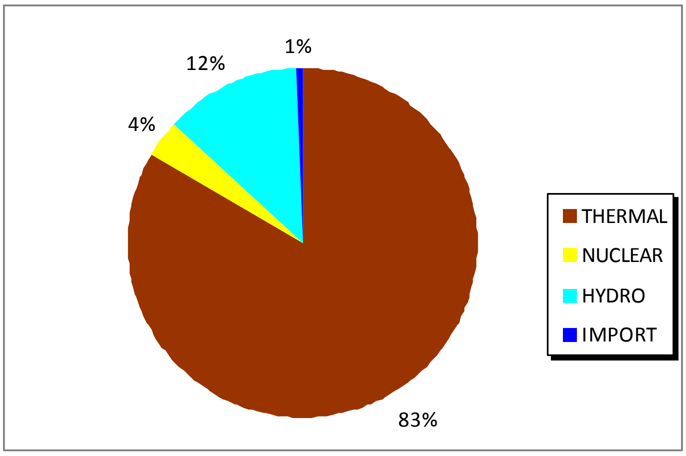
Power

More than 50 percent of the Indian population has little or no access to commercial energy for their living needs and livelihood. Even those who have access have to endure an erratic electricity supply as well as power cuts. The total installed generating capacity of power utilities climbed from 199 GW as on 31 March 2012, to 233 GW by December 2013---representing an increase of 17 percent. The installed capacity consists of 58.75 percent coal, 8.92 percent gas, 0.52 percent oil, 17.39 percent hydropower (> 25MW), 12.33 percent renewable energy sources (RES), and 2.09 percent nuclear energy. Out of this total installed capacity, the highest share is contributed by the state sector (38.83%), followed by the central sector (32.53%), and the private sector (28.64%), as shown in Tables 3.1 and 3.2.

In spite of the high demand for power utilities, the capacity addition has been lower than the planned targets. For example, this target was 78,700 MW for the 11th Five-year Plan (2007-2012) but the actual capacity addition was only 53,922 MW. This indicates an under-achievement of approximately 25,000 MW (Central Electricity Authority [CEA], 2011).

In terms of generation, India recorded a total of 912,056.70 million units (MU) of power (2012-2013). Figure 3.9 shows the source-wise distribution of power-generation in India for 2012-2013. Thermal sources generated about 760,675.80 MU (83%); hydroelectricity, about 113,720.29 MU (12%); nuclear sources, 32,866.11 MU (4%); and imports, 4,794.5 MU (1%) of the total generation in the country (CEA, 2013).

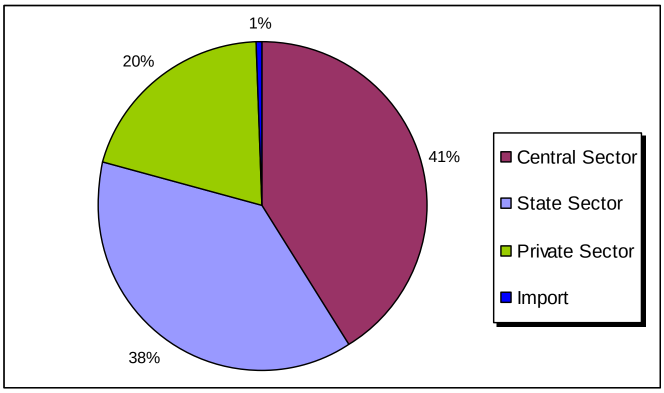
Figure 3.9: Source-Wise Generation of Power (MU), 2012-2013



Source: CEA, 2014.

On the other hand, Figure 3.10 shows the sector-wise distribution of power generated in India for 2012-2013. The central sector generated about 375,970.33 MU (41%); state sector, about 347,153.72 MU (38%); private sector's Independent Power Producers (IPPs) and utilities, 157,197.45 MU (17%) and 26940.7 MU (3%), respectively; and imports, 4,794.5 MU (1%) of the total generation in the country (CEA, 2013).

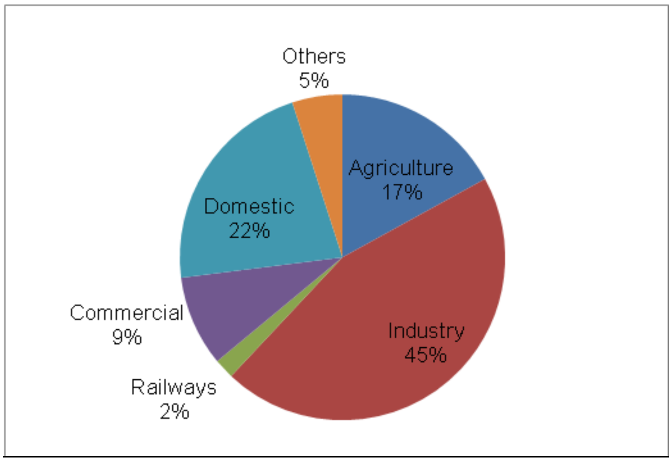
Figure 3.10: Sector-Wise Generation of Power (MU), 2012-2013



Source: CEA, 2014.

Finally, Figure 3.11 shows the sector-wise consumption of electricity in India in 2012.

Figure 3.11: Sector-Wise Consumption of Power in India, 2012 (%)



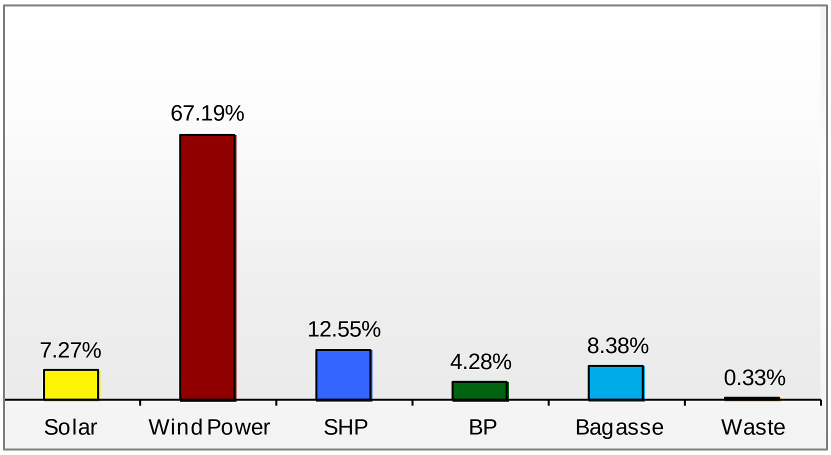
Source: MOSPI, 2014.

Renewable Energy Sources

India sees a potential for generating renewable energy from various sources: wind, solar, biomass, small hydro, and cogeneration bagasse. The country has the world's fifth largest wind power market and plans to add about 20 GW of solar power capacity by 2022. Renewable energy sources (RES) took about 12.33 percent share of India's total energy-producing capacity in 2013 (Table 1). In 2011-2012, the total potential for renewable power generation in the country is estimated at 89,774 MW. This includes wind power potential of 49,130 MW (54.73%), small-hydro power (SHP) potential of 15,399 MW (17.15%), biomass power potential of 17,538 MW (19.54%), and potential from bagasse-based cogeneration in sugar mills of 5,000 MW (5.57%).

The geographic distribution of the estimated potential (among the Indian States) reveals that Gujarat has the highest share at about 13.91 percent (12,489 MW), followed by Karnataka with 12.3 percent share (11,071 MW) and Maharashtra with 10.69 percent share (9,596 MW), mainly on account of wind power potential. Figure 3.12 gives the source-wise capacity of RES in India in 2012. Renewable energy sources are a feasible alternative as they bring environmental and socio-economic benefits along with potential energy security to India. About 32% of the total primary energy use in the country is still derived from biomass and more than 70% of the country's population depends upon it for its energy needs. At present, availability of biomass in India is estimated to be about 500 million metric tonnes per year. In addition, surplus biomass availability of about 120 – 150 million metric tons per annum is estimated, which includes agricultural and forestry residues, corresponding to a potential of about 18,000 MW. Further, the 5000 MW surplus power could be generated through bagasse-based cogeneration in the 550 sugar mills in India, provided that these mills adopt technically and economically optimal levels of cogeneration for extracting power from the bagasse produced by them (Ministry of New and Renewable Energy (Ministry of New and Renewable Energy MNRE, 2014).

Figure 3.12: Source-Wise Capacity of RES in 2012 (%)



Source: MNRE, 2014.

India's research and development on clean energy technology are funded by the National Clean Energy Fund (NCEF). To mitigate the alarming pollution levels in the country and to encourage development of RES, the Indian government, during the 2014 Union Budget, has proposed to increase the clean energy cess on imported coal from INR 50 per tonne to INR100 per tonne, and to raise the basic customs duty on bituminous coal to 2.5 percent from the earlier 2 percent. The amount of the cess collected will be invested in the NCEF (Press Information Bureau [PIB], 2014).

Nuclear Energy

Consumption from nuclear energy has increased from 5.2 Mtoe in 2010 to 7.3 Mtoe in 2011, comprising 1.2 percent of the total global consumption (BP, 2012). The gross generation from nuclear power in 2011-2012 was 32,455 million kWh with an availability factor of 91 percent. This represents an increase of 22.6 percent over the 2010-2011 period. India has nuclear reactors at six locations with a total installed capacity of 4,780 MW as well as 10 new nuclear power projects in the pipeline under the 12th Five-year Plan (2012–17). It owns five nuclear reactors under construction and plans to construct 18 additional nuclear reactors by 2025. As a result of the 2011 Fukushima nuclear disaster in Japan, India's atomic energy regulator will renew the operational license of all the 20 atomic power plants in the country only on a short-term basis---i.e., until the installation of additional safety measures as suggested by the Nuclear Power Corporation of India Ltd is in place.

Energy Trade

In its pursuit of energy trade, India needs to address existing issues such as poverty and ever increasing population, as well as find ways to ensure energy access and energy security. *Energy security* is defined as the continuous availability of energy in varied forms, in sufficient quantities, at reasonable prices, to fuel economic growth (IEP, 2014). While energy access refers to access to all modern forms of energy, the government schemes so far have focused essentially on electricity. Thus, India should focus on reducing its dependence on energy imports and diversifying its energy basket.

In India, about 75 million households still have no access to electricity. More than 80 percent of the households still use traditional fuels (fuel wood, agricultural waste, and biomass cakes) for cooking and general heating needs, while 43 percent rely on kerosene as their primary fuel for lighting. Under the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), a national electrification program of India's Ministry of Power, about 107,083 (out of 110,886 un-electrified villages) have been electrified. However, in many of these electrified villages, electricity still remains unavailable. Furthermore, where available, power supply is erratic and for couple of hours only. During outages, the rural population is forced to use kerosene and other traditional fuels for meeting their lighting and other energy needs (Census, 2011). The Ministry of Power, which is responsible for rural electrification, focuses mainly on grid extension.

The coal distribution system in India is governed by the New Coal Distribution Policy (NCDP), under which all major Independent Power Producers (IPPs), Captive Power Producers (CPPs), cement and sponge iron units seek coal allotments from the Ministry of Coal (MoC) through their nodal ministry. A standing linkage committee reviews and recommends the applicants to the coal companies for issue of Letters of Assurance (LOA). With this LOA in tow, unit holders then approach the coal companies for their coal supplies.

Trade within the Five Regional Indian Grids

India's state grids are inter-connected, consisting of five major transmission regions: the northern, north eastern, eastern, southern, and western areas. It started in 1991, when the north eastern region (NER) and eastern region (ER) grids were linked. After more than a decade, in 2003, the western and ER-NER grids were interconnected. Subsequently, in 2006, the northern and eastern grids followed suit. Thus, four regional grids: the northern, eastern, western and north eastern grids were synchronously connected to form a central grid operating at one frequency. Finally, in 2013, the southern region grid was also connected to the central grid in synchronous mode, thereby achieving the government's target of "One Nation-One Grid-One Frequency." This will, in turn, help in optimal utilisation of scarce natural resources by transferring power from resource-centric regions to load-centric regions. It will not only promote a vibrant electricity market but will also facilitate trading of power across various regions within the country (Power Grid Corporation of India Limited, 2014).

Due to diversities in different regions' industrial and household needs, there is some difference in their supply and demand for power and consequently, in the frequencies. Also, regions differ in the peak requirement hours within a day. That is, one regional grid reaches its day’s peak power demand while another regional grid is still below its peak requirement. Because of the large gap between demand and supply, these energy-surplus as well as energy-deficit regions sharing one central grid need to enter into energy (power) trade. Table 3.3 shows a cross-sectional representation of the imports and exports of electricity (2012-2013) among the five Indian regions sharing one central grid.

Table 3.3: Import and Export of Electricity within India (in million kWh) for 2013

	North	West	South	East	North East	**Total Export**
North	-	3,034.9	267.5	2,122.8	216.8	**5,642**
West	6,060	-	2,258.2	2,063	68.4	**10,449.6**
South	51.2	8.8	-	-	0.2	**60.2**
East	15,886.4	6,499.7	3612.7	-	1,977.2	**27,976**
North east	2.9	-	-	8.9	-	**11.8**
Total Import	**22,000.5**	**9,543.3**	**6,138.4**	**4,194.7**	**2,262.6**	**44,139.6**

Source: CEA, 2014.

India's eastern region is the largest exporter and northern region is the largest importer of power. The eastern region exports the highest units of 15,886.4 million kWh to the northern region, in particular. The northern region experiences severe power shortages throughout the year almost every year; hence, it imports the most units (22,000 million kWh), with a major share coming from India's eastern region.

Trade with South Asian Nations

India highly depends on fossil fuel imports for its energy demand mainly due to the scarcity of domestic reserves. The country imports nearly 80 percent of its domestic crude oil requirements mainly from West Asia. It also gets more than 10 percent of their domestic coal requirements mainly from Indonesia, Australia, and South Africa. Cross-border linkages include import of power from Bhutan and export of power to Nepal. While India is a net importer of energy, the increase in refining capacity has helped turn India into a net exporter of refined petroleum products, particularly middle distillates (PPAC, 2012).

In 2012-2013, India exported 63.408 MMT of petroleum products worth INR 3, 20,090 crore (US$58,848 million), an increase of 4.23 percent in quantity.

In terms of value, this is a rise by 12.45 percent (in INR) and 0.79 percent (in US$). On the other hand, India's import of petroleum products for the same period was 15.774 MMT valued at INR 68,363 crore (US$12,506 million), which marks a decrease of 0.47 percent in quantity. This also represents a 0.40 percent rise in Indian Rupees terms and a decline by 11.86 percent in dollar terms. India’s import of petroleum products is restricted to balancing domestic refinery production (MoPNG, 2013).

Low electrification rate in India is an obstacle to achieving energy security, energy access and opportunities for market integration with other South Asian countries. India’s poor energy trade network with the South Asian nations constrains the optimal utilisation and relative advantage of energy resources. It has no cross-border pipeline or trade in natural gas, while cross-border electricity interconnections and trade are insignificant.

Most of the South Asian nations have the potential to resolve the imbalance in supply and demand in the energy sector. The region is well endowed with energy resources, but these are unevenly distributed or unexploited. India, Pakistan, and Bangladesh have large reserves of gas and coal, while Nepal, and Bhutan have a tremendous potential of hydro-electric power. Meanwhile, Nepal, Bhutan, Pakistan, Myanmar, and Sri Lanka face acute power shortages. To mitigate such power shortage, the SAARC Energy Centre was set up in Islamabad in 2006. Its objective was to facilitate trade among India, Pakistan, Bangladesh, Sri Lanka, Nepal, Maldives, and Bhutan (Mahmud, 2012).

Promotion of cross-border electricity exchange and trade among the South Asian nations will ensure that there is optimal usage of the regional resources for electricity generation. For example, the hydro-electricity potential of Nepal and Bhutan could be exported to other South Asian Association for Regional Cooperation (SAARC) countries through common grid stations. India already has grid interconnections with Nepal and Bhutan, but more energy market integration would take place if other South Asian nations would connect to the said grid.

Some instances of bilateral trade between India and its trade partners are briefly discussed below.

India and Bhutan

India and Bhutan share the largest regional bilateral agreement (in terms of volume) for electricity trade for the past few decades. Bhutan exports of more than 75 percent of its generated electricity to India comprising 25 percent of the former's GDP (Energy Sector Management Assistance Program [ESMAP], 2008). India provides technical and financial support for the hydropower projects in Bhutan, and in return, it is entitled to import all the surplus power, after Bhutan's energy needs are met. Their bilateral cooperation aims to install hydro-power plants with a total capacity of 10,000 MW by 2020. Existing hydropower projects in Bhutan financed by India include Chhukha, Tala, and Kurichhu, which have installed capacity of 336 MW, 1,020 MW and 60 MW, respectively. Three more hydro-power projects---Punatsangchu I (1,200 MW), Punatsangchu II (1,020 MW), and Mangdechu (720 MW) are under construction and due to be commissioned by 2018 (MEA, 2014).

In April 2014, India and Bhutan signed an inter-governmental agreement on the Development of Joint Venture Hydropower Projects on four hydro-power facilities with a total capacity of 2,120 MW via public sector undertakings. These four hydro-power projects are the 600 MW Kholongchu, 180 MW Bunakha (which has 230 MW downstream benefits from Tala, Chukha, and Wangchu), 570 MW Wangchu, and 770 MW Chamkarchu. India's hydro-power cooperation with Bhutan is mutually beneficial since Bhutan earns revenues by exporting its clean and low-cost electricity to India, which also strengthens their economic and political relationships (Mahmud, 2012).

India and Nepal

Nepal's techno-economically feasible hydroelectric potential is estimated at 43,000 MW, of which only 627 MW have been developed. India has been assisting Nepal in the development of its hydro power potential through four projects viz., Pokhra (1MW), Trisuli (21MW), Western Gandak (15MW) and Devighat (14.1MW). In addition, four major water resources projects in Nepal viz., Pancheshwar (5600MW), SaptaKoshi (3300MW), Naumure (225MW) and Karnali (10800MW) are under discussion with their Indian counterparts at various levels, as mutual interest projects. Further, two

projects viz., Upper Karnali HEP (300MW) and Arun III HEP (900MW) are being developed by Indian CPSUs/IPPs (Ministry of Power [MoP], 2013)
The transmission capacity of the existing 132 kV and 33 kV lines between the two countries limits the exchanges to about a third of the agreed level of 150 MW. The power exchange agreement between India and Nepal has three major components; namely, the Dhalkebar-Muzaffarpur, Duhabi-Purnia and Butwal-Gorakhpur transmission lines, each with a capacity of 400 kV. Of these, the first phase construction of the Dhalkebar- Mujaffarpur's 400 kV transmission interconnection is under way. The transmission line from Dhalkebar to Muhaffarpur spans 140 km, but only 45 km of this transmission line lies within the Nepalese territory. Meanwhile, the Duhabi-Purniya line measures 112 km long, of which 22 km lies within the Nepalese territory. Similarly, 25 km of the 125 km Butwal-Gorakhpur transmission line lies within Nepal (ESMAP, 2008).

India and Bangladesh

The energy cooperation between India and Bangladesh was formalised in October 2013, with the inauguration of two collaborative power projects. The first project involves a transmission line to supply 500 MW of power from West Bengal to Bangladesh. This 125-km grid will establish a 400 kV double-circuit, cross-border link between the Bheramara of the western electrical grid of Bangladesh and the Baharampur of the eastern electrical grid of India. The system will facilitate an initial power flow of 500 MW into Bangladesh from the Indian grid, with a provision to boost the power flow to 1,000 MW (Mahmud, 2012). The second project includes a 1,320 MW thermal power undertaking in Bangladesh named "Maitri" (which means friendship). The Bangladesh-India Friendship Power Company is a joint venture between the National Thermal Power Corporation (NTPC) of India and the Bangladesh Power Development Board (Economic Times, 2013).

India and Myanmar

Myanmar has an estimated hydropower potential of 39,720 MW, of which only about 2 percent has been developed. India and Myanmar have collaborative agreements for the development of the Sedawyagi and Yeywa hydropower projects. India is also participating in the Tamanti multipurpose project with a hydropower component of 1,200 MW in the first stage. Inadequate investments in transmission and distribution grids meant to export power from Nepal to the northeast region of India (although already synchronised with the eastern and northern regions) hampers the power trade between these two countries (IPP Association of India, 2011).

India and Pakistan

In response to a draft Memorandum of Understanding presented by Pakistan to the Indian government, a feasibility study---together with the installation of transmission line to import 1,200 MW power from India---is likely to be carried out by the World Bank. The two nations have further coordinated technical working groups to review the initial implementation phase of the deal. In the project's initial phase, Pakistan is expected to import 500 MW from India, which would subsequently increase to 1,200 MW (Economic Times, 2014).

India-ASEAN Trade Relations

Since the early 1990s, the economic relationship between India and the ASEAN countries has improved significantly. India’s liberalisation program and economic reforms under the "Look East Policy" (1991) were initially aimed at developing an economic and strategic relationship with the ASEAN countries. Such trade of goods and services between India and other ASEAN economies is all the more significant in today's times.

The India-ASEAN economic relationship began in 1992. In 1995, India was accorded the full ASEAN Dialogue Partner status. It became a member of the ASEAN Regional Forum (ARF) in 1996, and of the East Asia Summit in 2005. It signed the Treaty of Amity of Cooperation in 2003 and has several bilateral free trade agreements with Singapore and Thailand, and on sub-regional initiatives such as the Mekong Ganga Cooperation Initiative and the Bay of Bengal Initiative for Multi-Sectoral Technical and Economic Cooperation (BIMSTEC) (Parameswaran, 2010).

Through regional trading arrangements (e.g., free trade agreements [FTAs]), preferential trade agreements (PTAs), and comprehensive economic cooperation agreements), India has shown its willingness to open its markets and liberalise trade. Agreements to promote and enhance mutual trade and economic cooperation among contracting states are either bilateral or multilateral in nature (e.g., the Asia-Pacific Trade Agreement; the BIMSTEC in 1997; the South Asian Free Trade Area [SAFTA] in 2006).

The signing of the ASEAN-India Free Trade Agreement (AIFTA) in 2010 further improved the potential for greater bilateral trade. According to AIFTA, India will slash import tariffs on 80 percent of the commodities it trades with the ASEAN, with the goal of reversing India's growing marginalisation in this region. The FTA is expected to increase bilateral trade to US$200 billion by 2022 and lead to talks on the Regional Comprehensive Economic Partnership (RCEP), which would also include Australia, China, Japan, South Korea, and New Zealand.

As far as energy trade with the ASEAN nations is concerned, Indonesia, Malaysia, and Brunei Darussalam provide prospects for mutually beneficial cooperation. Indonesia is important for energy trade relations with India as it is an important source of coal for India. Bilateral trade between India and Indonesia has been revised from US$25 billion to US$45 billion by 2015. In fact, beyond the regional FTA, India and Indonesia have started negotiations on a comprehensive economic cooperation agreement that would further liberalise trade (Times of India, 2012).

There are several areas for possible energy trade cooperation: oil and gas exploration, down-stream processing activities, etc. Various projects under way provide India the chance to support ASEAN nations, such as the Trans-ASEAN Gas Pipeline (TAGP) networks or the ASEAN Highway (AH) Network. Also, the Asia-Pacific Energy Cooperation (APEC) is a long-term project where India can play an important role (Nambiar, 2011).

The trade between India and the Mekong region is estimated to have increased from US$2 billion to US$17.4 billion over the past decade, thereby recording a compound annual growth rate (CAGR) of nearly 25 percent. Thus, the Mekong-India Economic Corridor (MIEC), a major India-ASEAN connectivity initiative, is a win-win proposition. Integrating the four Greater Mekong countries: Myanmar, Thailand, Cambodia, and Viet Nam with India through its east coast and northeast region, MIEC links these nations through a network of land and sea infrastructure. In terms of the land route, the MIEC proposes to connect Ho Chi Minh City (Viet Nam) with Dawei (Myanmar) via Bangkok (Thailand) and Phnom Penh (Cambodia) with India's northeast region. In terms of the sea route, Chennai on the eastern coast of India would connect to Bangkok, and the hinterlands to Viet Nam and Cambodia in the eastern direction and Myanmar to the west. The MIEC is foreseen as a dynamic industrial region wherein the economies will further integrate and collectively emerge as a globally competitive economic bloc (CII, 2014).

Energy Trade Barriers

Trade barriers are essentially government-placed restrictions on trade between nations. There are mainly two types of barriers: tariff barriers and non-tariff barriers. The tariff barriers refer to monetary restrictions such as taxes and levies imposed on trade to protect the domestic industry. Non-tariff barriers, on the other hand, refer to non-monetary restrictions that include documentation and packaging requirements; and, technical or safety standards. On the export side, they consist of barriers such as export subsidies, prohibitions, and quotas. On the import side, they include import licensing, bans, and custom procedures. India and its trading partners need to do away with the burdensome non-tariff barriers that impede free flow of trade. The following issues should be dealt with using a "fast-track approach" so as to mutually benefit partners.

- *Tariff Barriers*: The tariff barriers in India, like in other countries, have negative impacts such as inflationary pressures, government control and political considerations in economic matters, imbalance in demand-supply chain, strains on international trade relations. In India, subsidies on fuel (cooking gas and diesel), and on power and food supplied through the public distribution system have put tremendous pressure on the public finances. Fiscal deficit has grown after 2009, and market borrowings have risen from INR 2,470 billion in 2008-2009 to INR 5,075 billion in 2012-2013. The average annual growth of fiscal deficit in the last 10 years has been 13 percent (Narayan, 2014).

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Energy trade involves large amounts of expensive mechanisms, infrastructure and connectivity, and tariffs are very important for the potential investors. High tariffs create obstacles in the regional market integration as they protect domestic industry. Presently, the Indian economy is characterised by low growth, high inflation, high current account deficit and fiscal stress---factors that discourage foreign investment in trade and other sectors. Efficient fiscal planning and reduction/removal on energy subsidies can address these barriers.

- *Energy Pricing and Subsidies:* Distorted energy pricing and subsidy regimes in India and in the ASEAN region deter the commercial viability of trading in energy, as the entities that are selling energy at subsidised rates will have to pay for the energy at cost, with negative financial consequences. For example, India has a law that states that solar modules must be produced within the country before they can benefit from state subsidies.

- *Geopolitical Barriers*: Regional disagreements and conflicts between trading nations (India, Pakistan, Bangladesh, and Sri Lanka, for example) supersede attempts to augment energy trade. In spite of all the bilateral and multilateral agreements, India's energy trade with its neighbours is very limited. In fact, the full potential is yet untapped. At present, cross-border energy trade is limited among Bhutan, India, and Nepal.

- *Inadequate Infrastructure and Connectivity Issue:* The lack of an integrated gas and electricity infrastructure due to political and security reasons also hampers regional energy trade. To enhance the India-ASEAN trade relations and connectivity, the relations among Northeast India, Bangladesh, and Myanmar should be strengthened. India will benefit largely by improving trade relations with Bangladesh, which not only shares the longest international border with India (3,500 km) but is also strategically located along India's connectivity to Southeast Asia and China. Such forged relations will also reinforce the energy cooperation in the ongoing hydroelectric projects in the state of Sikkim (Upper Teesta) in India, Bhutan, and Nepal and help revive the Myanmar-Bangladesh-India gas pipeline project.

- *Lack of Trust and Unfavourable Political Climate:* Developing power trade networks with Nepal and Bhutan will benefit India as its peak demand is synchronised to the seasonal hydro power potential and production peak of these two nations. However, all three nations continue to suffer from power deficits due to lack of trust, unfavourable political climate, and issues over river water sharing (viz.,Kosi, Gandak, and Mahakali treaties). At present, the aim to have power trade agreements with Nepal and Bhutan is difficult to accomplish.

- Weak *Regulatory Policy:* Disagreements on energy pricing are other non-tariff barriers affecting power trading. For example, the power trade between India and Nepal poses a challenge as energy prices are not fixed commercially and there are inadequate grid interconnections and transmission lines available. Also, Nepal's lack of an integrated hydropower sector policy is another major issue hounding their collaboration.

- *Renewable Energy:* India has mandated a 5-percent ethanol blending in petrol and 5-percent biodiesel blending in diesel as well as set future blending targets of 20 percent. However, the lack of sufficient production and funds, high costs, competitive markets, inadequate infrastructure, lack of access to technology, and competing usage of land for producing food crops are the major impediments that need to be addressed.

- *Information Barrier and Lack of Transparency:* Lack of transparency and ineffective dissemination of trade-related information are also non-tariff barriers. Such lack of information and transparency on the country-specific trade procedures, norms, and regulations is not conducive to energy trade in the region. The introduction and implementation of new trade regulations must be intimated in advance to trade partners.

- *Trade Specifications Not In a Universal Language:* Many countries publish the trading norms and other related specifications in their national language. This non-tariff barrier makes it difficult for trading partners if no translated versions are made available.

Conclusions and Policy Implications

While there is a huge potential for regional cooperation, existing barriers---both tariff and non-tariff---are hindering this process. India needs to reform the bilateral relations with every member-nation of ASEAN in terms of the requirements of each member-country and that of its own. After all, the ASEAN and East Asia Summit (EAS) hold great promise for India's own economic development once its trade integration with the region is improved. This study recognises the obstacles to energy trade between India and countries in the ASEAN and suggests possible steps for removing these.

- Energy trade between India and the ASEAN countries may have significant economy-wide repercussions, including the energy-growth-development linkage. Thus, such impacts have to be taken into consideration during India's policy- and decision-making processes.
- Political agreements on energy trade can work in the nascent stages of trade, but unless they quickly evolve into sustainable commercial arrangements, they are not conducive to growth in energy trade.
- India could be a major regional player in the renewable energy sector as it has (1) longer solar insolation periods for solar energy; and (2) a large potential for various renewable energy forms. Its vast area of wastelands could be utilised for growing non-edible oil crops for liquid fuels and wood for thermal power, for instance.
- Private sector investments should aim to overcome regional energy security challenges in a mutually beneficial manner. India needs to negotiate joint venture projects that satisfy the commercial as well as capacity building requirements of its trading partners, too.

The study recommends the following measures to improve the energy trade in the region:

- *Smoothing Out Relations:* Political tensions can be addressed through continuous and serious dialogues, which can happen only through a promise of integration. India needs to earnestly resolve issues with its neighbours Sri Lanka, Pakistan, Nepal, and Bangladesh through a concerted effort and genuine cross-border diplomacy. Trade relations between India and Nepal need to be strengthened through sincere efforts from both sides. After all, Nepal has great hydropower potential, and because of North India’s proximity to the major power grids in Nepal, India can serve as a potential importer of this energy.

- *Building Relations Based on Trust*: India and its neighbours have to work at improving trade relations in the power sector by focusing on the “human dimension” of building trust on each other. In the initial stage, projects may be funded by the respective governments, while other private funding agencies can provide additional support through concessional loans and grants.
- *Trade-friendly Agreements:* India and its trading partners in bilateral/multilateral/regional agreements must work towards improving the dispute settlement mechanism and simplifying the customs procedures so as to make the energy trade less restrictive. Existing agreements must have a built-in mechanism to review any shortcomings and make changes. Bilateral power trading arrangements such as those between India and Bhutan need to be encouraged as they not only promote bilateral power integration but could also be expanded into a multilateral, regional power integration network.
- *Increasing Renewable Energy's Share:* The share of renewable energy in India’s installed capacity mix could be made bigger. The country currently lacks an integrated/national-wide economic perspective toward renewable energy, along with a comprehensive, research-backed policy on increasing the adoption of liquid biofuels. That is, although national energy policies already exist, the actual development of renewable energy is still largely dictated by individual states' own regulations and policies.
- *Infrastructure Development:* The South Asian economies are increasingly burdened by energy deficits, and setting up a regional power grid could help alleviate these deficits. Nepal and Bhutan have hydropower resources that India needs so as to meet its ever-increasing energy demands. The coal and natural gas resources of Bangladesh, India, and Pakistan can complement their neighbours' hydropower potential, thus optimising both the region's energy security and resource use. Myanmar, which is fortunate to have reserves for hydroelectric

power capacity and natural gas as well as a strategic location, has the potential to tap such opportunities. Developing physical and institutional infrastructure will facilitate regional energy trade as well as bring positive economic, social and environmental impacts such as accessibility to steady supply of power, job opportunities, and reduced emissions.

- *Addressing the Energy Security:* Reforms are needed so as to revive the energy security in India and sustain its unprecedented economic growth. India is largely dependent on coal to fuel its power sector, but the scarcity of coal is a major issue. There are several options to improve this situation. Encouraging private sector participation in the coal sector is one. In India, coal mining is restricted to the public sector, with the Coal India Limited and Singareni Collieries accounting for 82 percent of the annual domestic production. Private companies are only allowed to mine coal for their small captive use.

Giving the newly created coal regulatory body some statutory powers is another solution. This regulator was created in 2014 in light of the various issues plaguing the coal sector: decrease in coal production, issues with coal pricing, allotment of mines, etc. However, the regulator only has administrative (advisory) powers and lacks a statutory status. Thus, it has no authority to specify the price of coal.

Lastly, over 80 percent of India's mines are the open-cast type--- unlike China, which has mainly underground minds. To augment coal production, India also needs to consider underground mining, which is environmentally benign.

- *Less Rigid Trading System:* Pricing mechanisms must be flexible enough to increase the amount of fuel imports. Currently, the current pricing methods are inflexible and negatively affect consumer's fuel choices. In India, the subsidised prices of fuels such as kerosene and diesel resulted in artificially high consumption rates on one hand; and discouraged investments in clean energy, as it is perceived to be more expensive, on the other hand.
- *Other Measures:* A regional energy information database should be created, and transparency should be promoted in international trade. Also, a universal language should be used for all communications and

documents relating to trade. To relieve the pressure on the coal sector and lessen the dependence on imported oil and gas, renewable energy sources need to be harnessed.

India should also recognise that to promote regional energy trade, adjacent nations ought to be allowed to utilise and optimise the energy resources available within the region. Sharing of energy resources will help in meeting the energy demand as well as also act as catalyst to the region's economic or financial growth.

With the new leadership in India's government, positive changes are expected in various development sectors, including the energy sector. Recently, to enhance interaction among important ministries related to the energy sector, government departments such as the Ministries of Power, Coal, and New and Renewable Energy, were brought under one umbrella and assigned to one minister only. After all, to have a more meaningful relationship with the ASEAN, India needs to recover the momentum of its economy growth and, if it were to further such growth, it must bring about new reforms.

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CHAPTER 4

ASEAN-India Gas Cooperation: Redefining India’s “Look East” Policy with Myanmar

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As economic power shifts towards Asia---particularly China, India and the Association of Southeast Asian Nations (ASEAN) ---a robust energy cooperation within this region will help sustain the region's development. Cooperation master plans already in place include interconnecting power grids and gas pipelines, engaging in cross-border power projects and promoting freer trade of energy commodities among the countries. The East Asia Summit region (EAS) pioneers such cooperation not only within the ASEAN region and the Greater Mekong Subregion (GMS) but with nations such as India, Russia, the United States, and Australia as well. This study, though, focuses more on India and how its Look East Policy helps forged trade and other bilateral cooperation with the ASEAN nations, and how Myanmar plays a strategic role in India's energy security. This study also concentrates on a particular energy resource---natural gas---and develops a quantitative assessment model to evaluate India and its neighbouring countries' long-term natural gas demand, corresponding infrastructure requirements, and investment demand. Specifically, it looks at how India’s Look East Policy can help secure the required amount of natural gas from the ASEAN and East Asia region and at what cost.

There is nothing new with including Myanmar in a discussion on regional energy cooperation. After all, this is a country with abundant untapped natural resources, including hydro and natural gas. However, very few studies have so far focused on Myanmar’s strategic location and geography and how it can provide the non-energy resources---such as land, water, human resources, and maritime channels for seaborne trade---needed to develop a robust integrated energy market. All these are essential factor inputs for large-scale energy infrastructure projects. This study thus explores Myanmar's role in helping India with the latter's own energy security.

Through a three-stage analysis of the regional energy problem, the study demonstrates that India is eventually going to depend more on gas (after coal) for its energy supply. As India's home-grown gas supply is not sufficient to meet its domestic gas demand, it currently imports more than 75 percent of its requirement from Qatar. Given the growth in future demand, growing supply volatility of Middle East gas, and increasing gas prices (including Asian premium), any dependence on the Middle East's supply makes gas more expensive and vulnerable for India. Also, since more than 27 percent of the landed price of gas and LNG in the country consists of transport cost, it is important to reduce the distance of transport.

India's East Look policy in terms of exploring more energy cooperation with the ASEAN and East Asia has failed to produce any worthwhile results so far. However, Myanmar---which lies in the border of India and features untapped natural resources---has huge potential to help India meet the latter's near- to mid-term gas demand more economically. India could procure gas from Myanmar either by direct resource extraction or by using Myanmar as transit country to bring gas from ASEAN countries, especially by linking to the ASEAN Gas Network. This study further elaborates on the options available in the Myanmar-India collaboration under two different categories: (1) By hard infrastructure development; and (2) By developing soft linkages. Hard mechanisms include unilateral or joint development of Myanmar's gas fields, setting up of refineries or gas transportation systems (pipelines or LNG), and LNG port development. On the other hand, soft mechanisms include developing energy-efficient, gas-based power projects in Myanmar to reduce long-term domestic gas consumption, assisting Myanmar to move towards efficient gas market structures by bringing more reforms and market competition, and training Myanmar's domestic skilled workers to enable them to work in large-scale gas and LNG projects. This study further reveals that India is lagging far behind China in terms of hard gas infrastructure development in Myanmar. Nonetheless, there is potential for India to develop soft linkages within Myanmar's natural gas sector. Existing large-scale infrastructure development brings several environmental and social externalities that are not adequately addressed. With India's support, Myanmar can overcome such externalities as well.

Finally, for policy-making purposes, this study has the following recommendations:

1. Given its rapidly growing energy demand and need for energy security, India will benefit from a long-term cooperation with Myanmar;
2. A proactive and positive move towards joint gas field development, along with relatively aggressive measures to acquire new fields for gas exploration, could provide India better energy supply at cheaper costs;

3. India should develop soft linkages with Myanmar in the natural gas sector by providing technical knowledge, developing domestic skills sets and assisting Myanmar in its energy market reforms;
4. India should also help Myanmar develop energy-efficient, gas-based power generation, which could in turn allow more gas for export.
5. In terms of energy infrastructure linkages with the ASEAN, India may develop roads, railways and port facilities in Myanmar so that the latter can be tapped as a transit channel. This will not only benefit Myanmar financially but help India explore the ASEAN energy market as well.

Key words: Energy Market Integration, Natural Gas, India, Myanmar Energy

JEL Classification: Q43

Introduction

Since 2010, India has been redefining its position (along with China) as a regional economic and political powerhouse, as well as emphasising its relationship with the ASEAN and other East Asian countries[1]. By joining the East Asian Summit group and promoting closer trade relationships with ASEAN countries as well as with Japan and South Korea, India has been demonstrating a steady policy focus on the East.

India's "Look East" policy is not new but in fact has been inactive due to lack of concrete actions since the 1990s. Nonetheless, India's geographical proximity to and long relationship with the ASEAN should be enough reasons for it to revive its cooperation with the ASEAN and Far East countries. Moreover, the recent changes in India's leadership may further enhance the collaboration between India and the ASEAN (including South Asian Association for Regional Cooperation [SAARC] countries) in all possible economic activities, as per their promise in their election manifesto published in early 2014.

Given India's immediate need to improve its economy (e.g., to reverse its falling GDP growth rate, which is now below 5%), its government has to fast-track its programs for basic infrastructure development and the manufacturing sector. Energy, therefore, has a part in the whole process of development. Compared to the 2013 level of energy consumption, India's primary energy supply is around 4 percent to 5 percent per annum, which needs to be driven up to the 8-percent to 9-percent range by 2020.

Today, India is the fifth largest energy consumer in the world. Of the 12,000 million tonnes of oil equivalent (mtoe) of energy resources that the world consumes, India comprises 4.4 percent (524.2 mtoe). Global consumption of primary commercial energy (coal, oil, and natural gas; nuclear and major hydropower) has grown at a rate of 2.6 percent over the last decade. In India, demand grows at around 6.8 percent, while the supply is expected to increase at a compounded annual growth rate (CAGR) of 1 percent only. Of the total

[1] Protocol to amend the framework agreement on comprehensive economic cooperation between the Republic of India and the Association of Southeast Asian Nations.

primary energy consumption basket, oil and gas comprise 45 percent. Even if one exploits hydropower's potential to the fullest, or if there is a 40-fold increase in the contribution of renewable resources and a 20-fold spike in the contribution of nuclear power capacity by the year 2031-2032, fossil fuels will continue to take a 74-percent to 85-percent share of the energy mix.

Growing Importance of Natural Gas in India

Although India's energy supply portfolio is envisaged to skew towards coal in the near future, natural gas will continue to increase its contribution to the supply portfolio. Factors such as (in)availability of good and affordable quality coal, lack of investment in coal mining, allocation of coal beds for mining, coal prices, and increasing concern over environmental pollution explain why the competitive advantage remains with natural gas. Natural gas comprised 4 percent of the country's total primary energy in 1999, and further rose to 10 percent by 2010. By 2025, natural gas is expected to comprise almost one-fifth (20%) of India's primary energy supply. India's gas demand will be 132 Bcm by 2030 with an average per-year growth rate of 5.4 percent, one of the highest in the world.

India has a total proven gas reserve of 38 trillion cubic feet (Tcf). Its demand for gas is around 189 MMSCMD, while the total supply is around 168 MMSCMD. Out of the total supply, only 122 MMSCMD is domestically produced; the rest is imported as liquefied natural gas (LNG). Given India's gas reserve situation, LNG importation is inevitable. Therefore, India's natural gas supply can be secured by improving the regional gas supply, particularly by including Myanmar in the picture. Energy market integration is thus a potential solution to India's widening energy supply-and-demand gap.

This study explores options on how to augment India's natural gas supply, mainly by considering external sources (gas importation) that are cost competitive. Since natural gas is envisioned to remain part of India's future energy demand, the study further investigates the role of ASEAN countries, particularly Myanmar, and how to improve mutually agreeable trade and investment in the natural gas sector.

The next section lists the objectives of this study. Thereafter, Section 4 of this paper deals with the current state of India's energy security, with focus on natural gas vis-à-vis the country's targets. Section 5 discusses the ASEAN energy situation, particularly its energy supply and demand condition, and its potential as a reliable supplier of energy to India. Section 6 further analyses the importance of natural gas in several Asian nations' energy security. Sub-section 6.1 looks at a list of potential cross-border natural gas and LNG projects between ASEAN and India and the benefits of collaboration.

Section 7 compares the investment demand in the South Asian region, mainly dominated by India, under an enhanced regional trade collaboration in the natural gas sector. The next section (Section 8) focuses on costs related to pipeline and LNG-based gas trade between the ASEAN and India. In particular, the section talks about how India's bid to build a low-cost gas supply chain in the mid to long term will benefit the ASEAN and Myanmar. Sections 9 and 10 further explain why Myanmar is strategically important to India and why bilateral cooperation can enhance and secure the latter's long-term, low-cost gas supply. Finally, the study provides recommendations on how both regions can improve and benefit from their gas trade cooperation.

Objective of This Study

While India will be increasingly dependent on gas for its energy supply, its current home-grown gas supply is not sufficient. It currently imports more than 75 percent of its requirement from Qatar. Given India's future demand growth, along with supply volatility in the Middle East's gas and rising prices (including Asian premium), any dependence on the Middle East's supply will be expensive for India as well as expose the latter to vulnerabilities. Also, since more than 27 percent of landed price of gas and LNG in the country consists of transport costs, it is therefore important to reduce the distance of transport. Meanwhile, India’s Look East policy, especially in terms of exploring energy sector cooperation with the ASEAN and East Asia, has failed to produce any good result so far.

Meanwhile, Myanmar's rise in the region's geopolitical map, its untapped natural resources, and location in the border of India all explain why this nation is a strategic factor in India's efforts to meet its near- to mid-term demand for gas at a more economical price. India can procure gas from Myanmar either by direct resource extraction or by using Myanmar as transit country to bring gas from the ASEAN countries.

The primary objective of this study, therefore, is to demonstrate that regional energy market integration---particularly between Myanmar and part of the ASEAN, and India---can provide more strategic and sustainable energy supply to India. In this context, the study evaluates how India's existing Look East policy can be strengthened and, in the process, help diversify its energy supply portfolio (mainly natural gas) and improve its energy security.

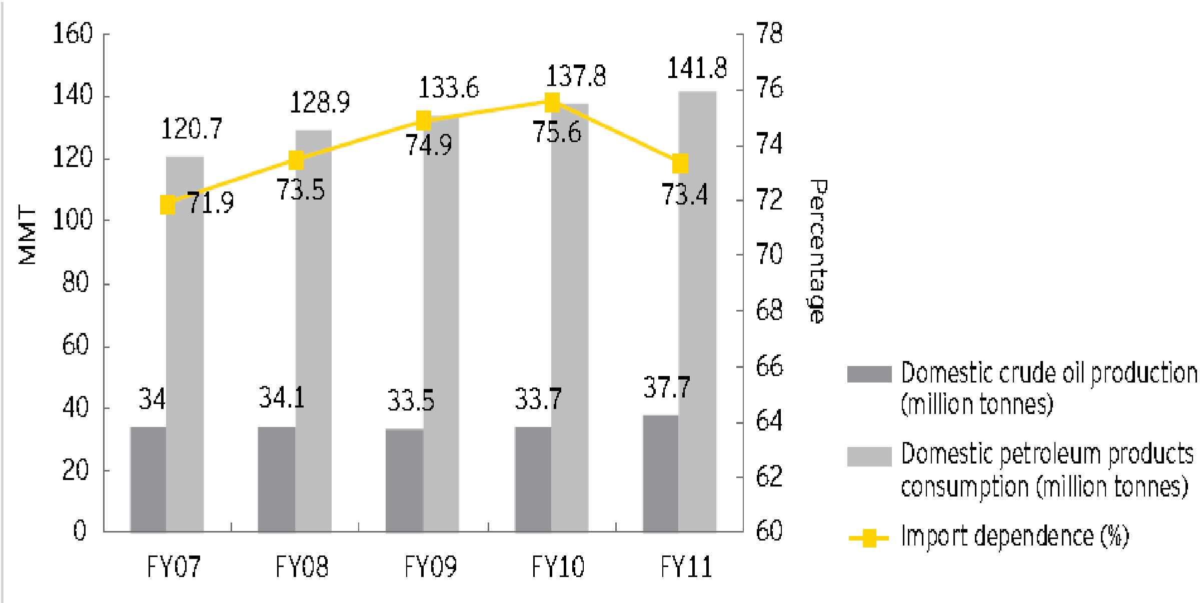
This study also intends to explain Myanmar's strategic position in India's sustainable energy supply chain by identifying potential hard and soft linkages between the countries in the development of natural gas. Finally, it will also estimate the gas sector's investment demand and range of economic benefits to beneficiary countries.

India's Energy Security

India is one of the world's fastest-growing economies, averaging an annual real economic growth of 8 percent in the past decade. Meanwhile, its energy sector sees an average 6.5-percent growth in demand yearly. Thus, along with the projected economic growth, energy demand is expected to rise. This rising energy demand, in turn, makes energy security increasingly important. India, however, has to grapple with the fact that its supply of natural gas from domestic fields continues to be below projection levels.

This combination of stagnant domestic production and mounting demand explains India's rising dependence on imported oil in the past few years (Figure 4.1). Thus, any threats to the supply of crude oil have always been a cause for concern. For example, the recent political turbulence in the Middle East, especially in Libya and Egypt, triggered a sudden decrease in crude oil production in the region, causing crude oil prices to spike and, in turn, drive up inflation in India. Also, the recent depreciation of the rupee, which raised the cost of crude oil imports for India, had an inflationary effect on the economy.

Figure 4.1: India's Past Trend of Energy Security

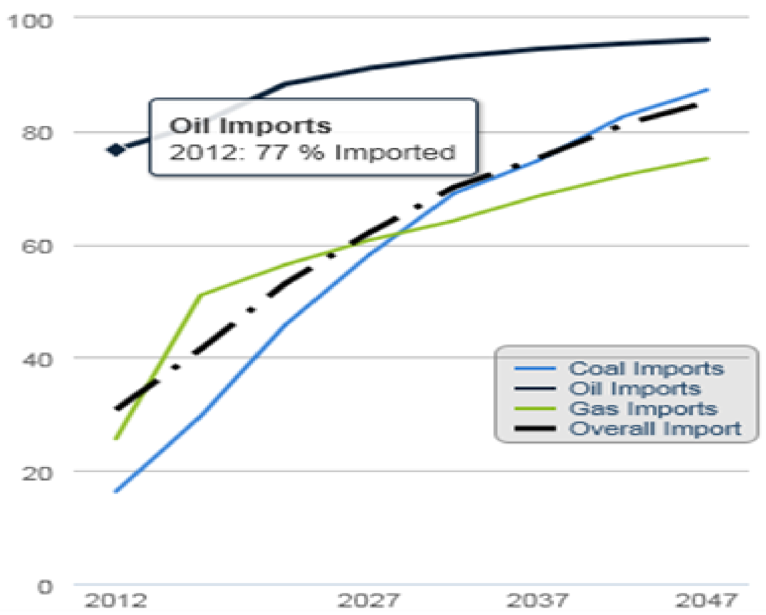


Source: FICCI, EY (2011).

However, assuming India's future growth prospect continues to be bullish at least until the 2030s, its energy security status might worsen if it allows itself to be over-dependent on imported coal, oil, and natural gas.

Figure 4.2 below shows the future trend of energy security (% of fuel import) in India. It shows that India's dependence on imports can even go up to 80 percent of the total energy supply by 2050. Energy security here is defined as the percentage of imported fuel compared to total energy supply in the country.

Figure 4.2: Future Trend of Energy Import Status in India



Source: India Energy Security Scenario 2047

To improve the country's energy security, India not only needs to reduce its fuel import but must also secure more reliable and affordable supply of energy across the borders. Given India’s humongous energy demand, it is unrealistic to believe that domestic supply can fully and efficiently meet the national energy demand. The more reasonable assumption is that India will continue to import a certain level of energy until such time when all domestic resources are exploited, and coal has become its major source of energy (India Energy Security Scenario 2047, 2014). However, in terms of energy-related emissions, coal-ran energy systems produce the highest amount of greenhouse gas emissions, which can damage the environment, ecology, and human health. India, therefore, has to strike a balance between energy security, economic development, and environmental quality. This is why a natural gas-based economy is one of the solutions for India. Natural gas is less polluting, highly efficient and easily movable from one place to another. As far as India's energy supply is concerned, natural gas is expected to play an important role in the coming years.

Importance of Natural Gas in the Region

Natural gas is an alternative to the world's rapidly depleting supply of oil. Like oil, natural gas can be easily transported from wellheads to destination points either by pipelines or by tankers. Liquefied natural gas has been at the heart of this evolution. In fact, LNG's global trade is set to increase by over 2 percent per year for the next 20 years. It is expected to reach 427 Bcm by 2017, with over 300 Bcm going to Asian markets, according to the International Energy Agency's (IEA) forecasts. In the past three years, Qatar has emerged as the leading LNG exporter, as it accounts for 30 percent of LNG trade in 2011. Interestingly, Australia is set to overtake Qatar as the leading LNG exporter by the end of the decade. More importantly, the global LNG balance has shifted to Asia---not only to mature markets such as Japan and South Korea, but also to China, Thailand, and India. The good news for Asian customers is that most of it will come from the Pacific basin, particularly Australia, Papua New Guinea, and Indonesia. Much of this will be within the borders of countries. However, an increasing amount will cross international borders.

The world's LNG trade in 2011 grew by 8 percent (or 17.7 MT), to reach a new high of 241.5 MT, primarily due to the sharp increase in demand from Japan (by 8.2 MT) right after a major earthquake and tsunami hit the country in March 2011 and damaged its Fukushima nuclear power plant. Increased demand from the United Kingdom (by 4.4 MT), India (by 3.4 MT), and China (by 3.3 MT) more than offset the 3.4 MT decline from Spain and the 2.6 MT drop for the United States, which continues to increase consumption of domestic unconventional gas.

The LNG trade grew stronger than anticipated in 2011, not just in volume but in geographic reach as well. Since 2006, five new countries started exporting LNG while 10 new markets began importing the product. The LNG exporting nations consist of Algeria, Australia, Brunei, Egypt, Indonesia, Libya, Malaysia, Nigeria, Oman, Qatar, Trinidad and Tobago, the United Arab Emirates, and the United States. At the same time, the price differential between oil-linked spot and Henry Hub prices for LNG has created new opportunities as well as challenges for the industry.

Table 4.1 demonstrates that the entire South and Southeast Asian regions have comparatively less natural gas reserves and reserve-to-production (R/P) ratio compared to the rest of the world. On average, the region has only 31 years of reserves compared to the Middle East region's (mainly Qatar's) more-than-100 years of reserves. Moreover, within the Asia Pacific region, Southeast Asia has far better reserves than South Asia. India and Bangladesh have a combined 40 years of reserve only, compared to the Southeast Asian countries' over-200 years of reserves. Table 4.2 shows that apart from Indonesia, Malaysia, and Myanmar, the rest of the regions' countries are net gas importers.

Table 4.1: Comparison of Gas Reserve and Reserve-To-Production Ratios

Region	Total Reserve (TCM)	Share Of Total Gas Reserve (%)	R/P Ratio
Brunei	*0.3*	*0.2*	*23*
China	*3.1*	*1.7*	*29*
India	*1.3*	*0.7*	*33*
Indonesia	*2.9*	*1.6*	*41*
Malaysia	*1.3*	*0.7*	*23*
Myanmar	*0.2*	*0.1*	*17*
PNG	*0.4*	*0.2*	*>100*
Thailand	*0.6*	*0.2*	*7*
Viet Nam	*0.3*	*0.3*	*65*

Source: Compiled from BP Statistics of Word Energy 2013

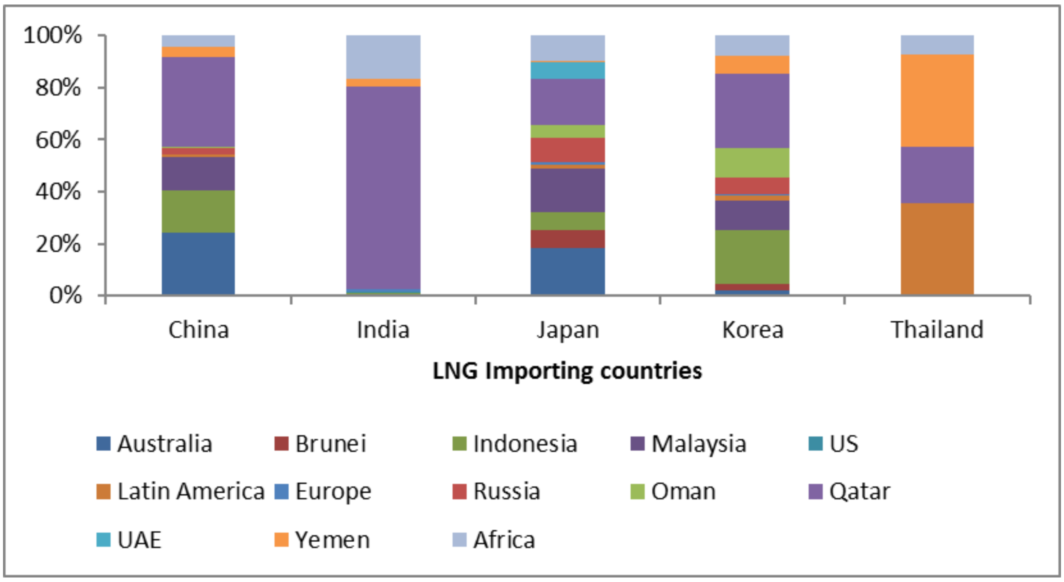
Table 4.2: Export and Import Status of Natural Gas of India and ASEAN (In Bcm)

Countries	2005	2006	2007	2008	2009	2010	2011	2012
India	6.04	7.99	9.98	10.79	11.76	11.04	14.99	14.35
Indonesia	-37.9	-37.1	-36.3	-36.4	-34.6	-41.7	-38.6	-35.3
Malaysia	-29.7	-29.6	-31.2	-30.9	-30.4	-30.7	-33.3	-31.9
Myanmar	-12.2	-12.6	-13.5	-12.4	-11.6	-12.4	-12.8	-12.7
Philippines	3.28	2.74	3.29	3.44	3.48	3.26	3.56	3.41
Singapore	6.84	7.05	8.62	8.24	8.06	8.40	8.77	8.31
Thailand	8.86	8.98	9.36	8.58	8.31	8.82	9.59	9.85
Viet Nam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	-2.6	-2.4	1.3	1.0	4.3	12.1	27.8	36.6
Japan	78.6	83.7	90.2	93.7	87.4	94.5	105.5	116.7
Korea	30.4	32.0	34.7	35.7	33.9	43.0	46.3	50.0

Note: negative values are export figures.
Source: Complied from BP 2013 energy statistics.

Figure 4.3 shows the current LNG imports of major countries in the region. Supply portfolio diversity is important in a nation's energy security because the higher the diversity ratio, the better the risk-hedging capacity of the country against supply disruption, price escalation, etc. It is observed that India's sources for LNG supply are less diverse compared to Japan's, which boasts the highest diversity ratio of LNG supply. India is mainly dependent on Qatar gas. In contrast, Thailand, for example, imports from Yemen as well as Latin America. China is gradually diversifying its sources by shifting more towards ASEAN regional suppliers.

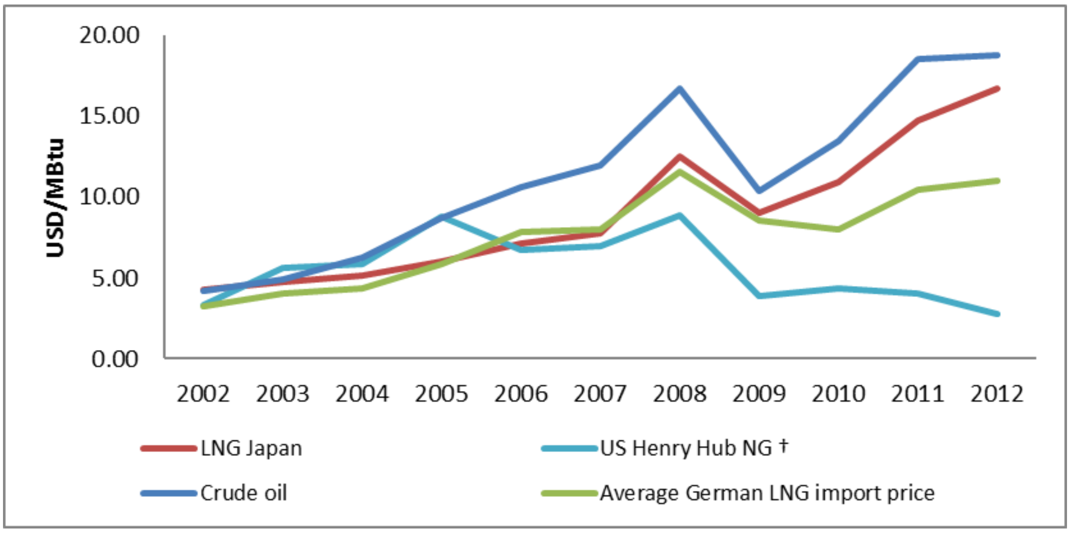
Figure 4.3: LNG Import Portfolio of Major Countries (as on 2012)



Source: Compiled from BP 2013 Energy Statistics.

As a matter of fact, Asian customers of LNG are paying premiums on each unit of LNG purchased outside of the region. It has been clearly shown in the Figure 4.4 where Japan's LNG import price is way above the average German price for long term contract. Since 2013, things are started changing. Japan, India and Korea are now joining hands to combat this increasing price of LNG import. Japan already stared diversifying its supply from Russia and United States, where India is also trying to find an alternative supplier

Figure 4.4: Natural Gas Prices in the International Markets

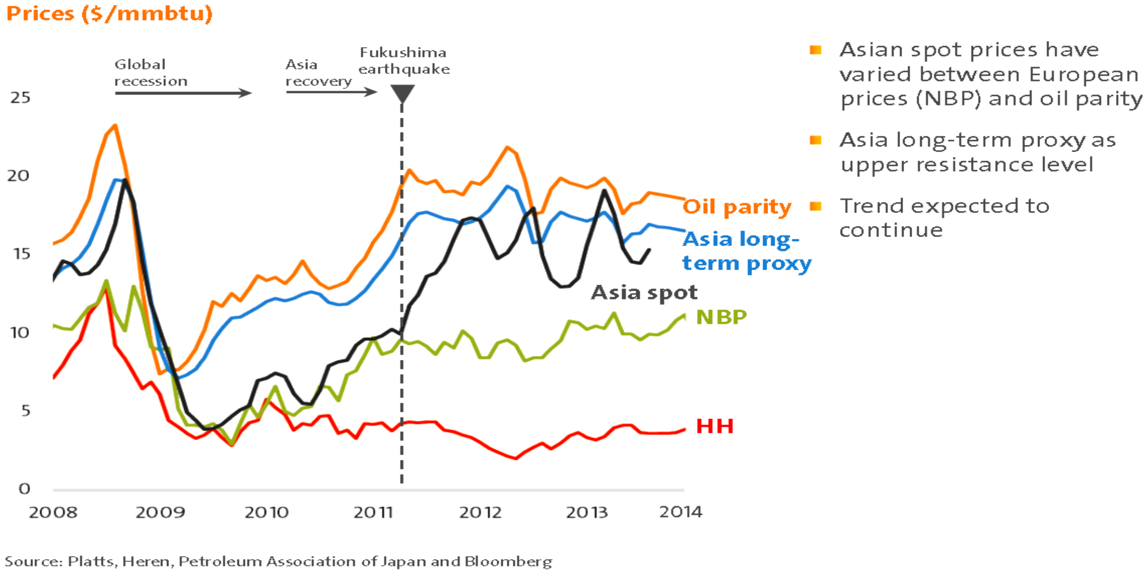


Source: Compiled from BP 2013 Energy Statistics.

The Asian LNG Importers' Group and Enhancing Bargaining Capacity

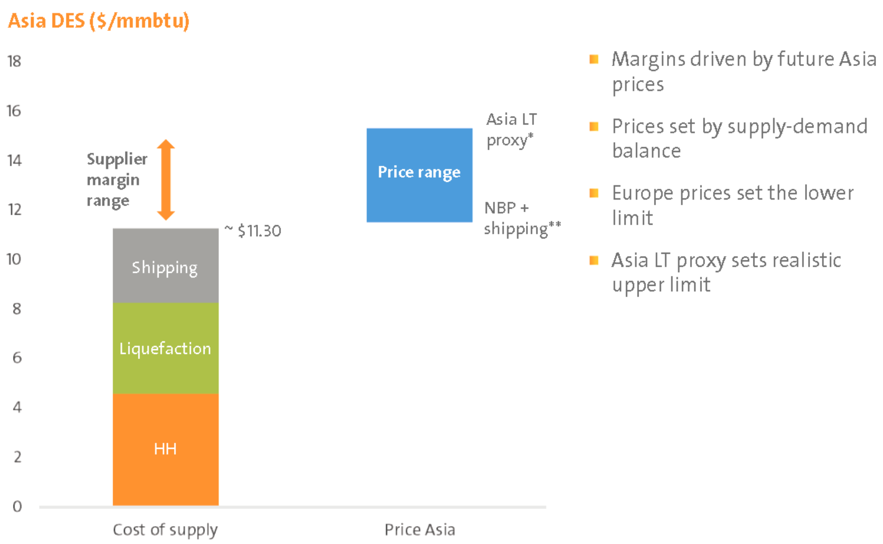
The earlier section has noted that the LNG prices in Asia are substantially higher than those in other major regions such as Europe and North America. Even as the view on natural gas as an alternative fuel for oil is waning and the rationale for such pricing is less clear today compared to the past, majority of LNG contracts in the Asia Pacific have a pricing formula that is linked to the oil price. Asian LNG importers such as Japan and China paid as much as US$15.75 per million British thermal unit (MMBtu) in middle of year 2013 compared to $2.97 per MMBtu paid by LNG buyers in the US Gulf Coast and $9.79 per MMBtu by British consumers, according to the US Federal Energy Regulatory Commission. Similarly, India's LNG imports are expected to rise to 19 percent by 2014, according to industry estimates. Japan as well as India are struggling with higher fuel imports, especially due to their weakening currencies. China, South Korea, Taiwan, and Singapore are also major LNG consumers and expected to lead the demand for LNG. In fact, Asia-Pacific countries will account for 64 percent of LNG demand by 2020. Meanwhile, Japan and India are also seeking cooperation opportunities with other LNG importers to improve their bargaining positions with energy exporters. Figure 4.5 below shows how the Asian LNG price is way above European prices and below oil parity price, which justifies the need for a regional importers' group.

Figure 4.5: Asian LNG Price Comparison with Others



If the Asian LNG price was to be decomposed further (Figure 4.6), one can find that around 20 percent of the cost of supply is due to shipping and around 20 percent to 30 percent is the suppliers' margin. More than 50 percent of what Asia is paying for is therefore the flexible component of the total price---a price that can still be adjusted by increasing the region's bargaining power and reducing the shipping distance.

Figure 4.6: Decomposition of Asian LNG Supply Cost



Note: Figure assumes JCC= $100/bbl , NBP= $10.03 and
* Asian Long Term (LT) proxy = 0.1485XJCC+0.50 and
**Additional shipping from UK to Asia
Source: BG LNG Market Outlook 2013

Figure 4.5 further corroborates the need for a regional LNG supplier in Asia. However, since LNG is highly price sensitive, lowering its price can demotivate investors from setting up new LNG plants in the region. It has been envisaged that a reduction in Asian LNG premier price can even reduce the export of gas from North America and Russia. On one hand, to keep the investors' interest up, the LNG price needs to be above a critical level; on the other hand, LNG price should be lower than a forbidden limit that will keep the buyers in the market. As a matter of fact, Singapore becoming Asian LNG hub with India joining Japan and China to form a regional importers' group can further strike a balance indeed.

The next section of this study first describes the current state of the natural gas demand and use in India and other ASEAN countries, which are both potential buyers as well as sellers of gas. Next, the paper highlights the potential benefits from cross-border gas infrastructure projects.

India

Because of rapid industrialisation, India's natural gas consumption is projected to grow from 6.6 Bcf/day in 2010 to 14 Bcf/day by 2035 (EIA, 2011). Its domestic production of natural gas, which has been its major source of gas, failed to grow fast enough to meet rising demand. Thus, India relies on imported LNG. Liquefied natural gas terminals have, in fact, been constructed in the country in recent years. Petronet LNG Limited of India set up the country's first LNG receiving and regasification terminal at Dahej, Gujarat, and is in the process of building another terminal at Kochi, Kerala. In 2011, the state of Gujarat, where two of India's four LNG import facilities are located, proposed to increase its annual LNG import capacity to 1.2 Tcf (3.3 Bcf/day) from 0.5 Tcf (1.4 Bcf/day) (Shah, 2011, May 24).

Indonesia

While oil production in Indonesia has been declining since the mid-1990s, its gas production has been rising in recent years, reaching 81 Bcm in 2011. Infrastructure is the most significant challenge to gas production in Indonesia as the bulk of the country's gas resources is located on the outer islands, far from demand centres in the island of Java.

Indonesia's government has prioritised the production of gas for domestic use, which could reduce the future availability of gas for export. Its proven gas reserves are just over 300 Bcm, with the largest production areas found in Sumatra and East Kalimantan. Meanwhile, the biggest undeveloped prospect is located offshore, in the East Natuna Block, which holds about 130 Bcm of gas reserves. Other promising areas that have yielded notable discoveries in recent years include West Papua and Sulawesi.

Indonesia has historically been a significant exporter of gas---mainly LNG---to Japan, Korea, and China. In fact, in 2012, Indonesia was the world's fifth-largest LNG exporter. Its three operating LNG liquefaction plants (Bontang, Arun, and Tangguh) have a combined capacity of 45 Bcm per year. However, exports have begun to decline because of falling production at the Arun liquefaction plant in northern Sumatra, which is being wound down in preparation for its conversion into a regasification terminal in 2014.

Two new liquefaction plants, Sengkang and Donggi-Senoro, are being built on the island of Sulawesi. Furthermore, there are plans to expand the Tangguh plant and Abadi Floating Liquefied Natural Gas (FLNG) project in the remote Arafura Sea. Indonesia's first regasification terminal, a floating storage and regasification unit (FSRU) in West Java, started receiving deliveries in 2012. Two others were under construction as of mid-2013, with more expected to be built so as to meet the domestic market's gas demand.

Malaysia

Malaysia's gas production in 2011 was at 56 Bcm, the second largest in the South and Southeast Asia. Production from offshore Peninsular Malaysia, including the Thailand-Malaysia Joint Development Area, caters specifically to domestic users, while production from offshore Sarawak feeds the 33-Bcm MLNG (Bintulu) liquefaction terminal. The nation's gas production is projected to rise in the medium term, reaching about 70 Bcm in 2020 before declining slightly to 65 Bcm in 2035.

Proven gas reserve is currently at 240 Bcm. A ninth liquefaction train expected in 2015---soon to be the world's first operating FLNG facility---will expand capacity by 15 percent. Construction has begun on the Kanowit FLNG terminal, which will be used to develop fields offshore Sarawak.

Malaysia is the world's second-largest LNG exporter, with Japan, Korea and China as main customers. However, Peninsular Malaysia is expected to consume more gas, given its population and economic activity, which may reduce their net gas export over time. Specifically, its net gas export is expected to increase to about 30 Bcm by 2020 but because of the rising domestic gas demand, will fall to 17 Bcm by 2035.

In 2013, Malaysia became both an exporter and importer of LNG, when it commissioned the 5.2 Bcm Lekas regasification terminal in Malacca. The facility is under long-term supply contracts with Qatar Gas and Gladstone LNG (Australia), while at least two other small regasification terminals (Pengerang and Lahad Datu) are in the offing.

Brunei

Brunei Darussalam has sustained its gas output at around 12-13 Bcm per year despite declining oil production. Southwest Ampa, its largest producing gas field, hold the majority of its production although in the future, prospects are hinged on explorations in the deep waters of the Baram Delta. Most of Brunei Darussalam's gas production feeds the 9.8-Bcm Brunei LNG liquefaction plant, which exports to Japan and Korea under long-term contracts. Production is projected to increase to a modest 14 Bcm by 2030.

Viet Nam

Gas production in Viet Nam has grown steadily in the past decade, reaching 9 Bcm in 2011. The Lan Tay field in the Nam Con Son basin, located offshore southern Viet Nam, supplies gas to the onshore Phu My power plant and provides almost two-thirds of the country's total output. As domestic gas demand growth is expected to outpace production, the Thi Vai LNG regasification terminal will be built and completed by 2016. A second regasification terminal is also planned. Viet Nam's gas production is projected to remain relatively steady throughout the projection period.

Thailand

Thailand's gas-producing fields, including the PTT EP-operated Bongkot field---the country's largest---lie offshore of the Gulf of Thailand. After the Joint Development Area shared with Malaysia came online in 2011, Thailand's gas production became 28 Bcm per year. Net imports of gas were 11 Bcm in 2011, majority of which were from the pipeline from Myanmar. With domestic demand outpacing production, the country began taking LNG shipments in 2011 following the opening of the Map Ta Phut regasification terminal. The Overlapping Claims Area with Cambodia is promising in the long term, although its development hinges on the two countries' resolution of their long-standing territorial dispute.

Efforts to maintain gas output will hardly be enough to stave off the expected 75-percent fall in Thailand's gas production by 2030-2035. For this reason, coupled with rising domestic gas demand, net gas imports will rise to almost 60 Bcm by 2035, most likely via the Myanmar pipeline.

Myanmar

Myanmar has a notable potential to increase its gas production. The bulk of its output currently comes from the offshore Yadana and Yetagun fields, which mainly supply Thailand. Meanwhile, production at the offshore Shwe field---the primary source of gas to feed the newly commissioned Myanmar-China gas pipeline (July 2013) ---is ramping up. With a transmission capacity of 12 Bcm per year, the pipeline will support rising exports to China's Yunnan province based on a 30-year agreement. The government has sought to increase foreign investment in the energy sector following the lifting of economic sanctions, and has attracted strong interests in several acreage offerings since 2011. However, it will take time to develop additional prospects, and it is unclear whether future gas supplies will be for domestic use or for export. The government issued a tender in July 2013 to import higher volumes of LNG.

The availability of infrastructure will be an important determinant of future exploration activities and production. Many of Southeast Asia's gas production areas are located far from demand centres and will require either an expansion of transmission infrastructure or LNG liquefaction facilities to ship the gas to regasification terminals domestically or abroad. The Trans-ASEAN Gas Pipeline project aims to establish broader gas interconnections throughout the region, but progress has been slowed down by a shortage of gas sources and huge investment requirements. Meanwhile, several countries are either building or considering to build floating liquefied natural gas facilities so as to develop remote resources as well as regasification terminals for receiving imported gas.

Table 4.3: Gas Production by Country in the Southeast Asia Regions (Bcm)

	1990	2011	2020	2025	2030	2035	2011-2035*
Brunei Darussalam	9	13	16	15	15	14	0.5%
Indonesia	48	81	108	118	129	139	2.3%
Malaysia	17	56	71	68	67	65	0.6%
Philippines	0	4	5	5	4	4	0.2%
Thailand	6	28	19	15	11	7	-5.5%
Viet Nam	0	9	13	12	12	12	1.3%
Share of world	4.0%	6.0%	6.3%	5.8%	5.6%	5.3%	n.a.

Source: Compiled from reports published by International Gas Union in 2011 and 2013, Wijayatunga and Fernando (2013), ADB (2012) and Gippner (2010), World Bank (2013), The New Age (2013), CIA (2013), Hameed (2011), ADB/ADBI (2009), Rahman, *et al*. (2013), Thant, *et al*. (2013)

Scope of ASEAN: India Gas Cooperation and Energy Market Integration

The previous section of this study has just established how natural gas will be part of the regional energy supply mix. The sector's growth and development in the region nevertheless, depends on various issues:

- ***How quickly the planned addition of liquefaction capacity is implemented, or at least how easy the Final Investment Decision (FID) is sought***. An additional 180 MTPA liquefaction capacity is expected to come online by 2016, of which 80 percent is in Australia, Indonesia, and Malaysia.

- ***How other players in the global LNG market respond to the rapidly changing situation***. Qatar is the single largest competitor in this sector. However, recent increases in Qatar LNG price in the Asia market puts them in competition with the US and East African suppliers. As increasing price of LNG in the market can be seen in two ways: It can be an opportunity for investors to put their money further in the energy sector's growth or it could be a cause for alarm to LNG investors considering that the sector is highly price elastic to alternative options such as piped natural gas[2].

- ***How the region's regasification capacity project is going to be built*** Of the 94 MTPA of the world's regasification capacity expected to be online by 2016, around 60 MTPA will be in the Asia Pacific region itself. Nonetheless, the regasification capacity is still lower than the requirement. Investors are still very skeptical about the growth prospect of the LNG market in the region given the rising price (i.e., rising beyond \$17 to \$18/MMBtu) of LNG compared to other fuels.

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[2] To attract investors to an LNG project, the price of a unit volume of natural gas delivered into a bulk distribution pipeline must at least equal the combined costs of producing, liquefying, transporting, storing, and regasifying, plus the costs of the capital needed to build the necessary infrastructure—and a reasonable return to investors. A major portion of the total cost of the LNG value chain is usually in the liquefaction plant (nearly 40%), while the production, shipping, and regasification components account for nearly equal portions of the remaining costs. It has been noticed that the costs of all components of the LNG value chain have declined during the last 20 years because of modification in technology.

- ***How shale gas is going to shape the gas market in the near future.*** From 2015 onwards, the United States will be exporting shale gas to the global market, making it a net LNG exporter. In fact, the United States has started exporting gas to Asia, especially to Japan and China.

- ***How transportation cost is a crucial factor in LNG's long-term business viability.*** The pricing of LNG in South and Southeast Asia is mainly driven by both the Japan Crude Cocktail (JCC) price and the "slope" used to link the LNG price to the oil market price. It is understood that the higher the crude oil price in the international market, the more attractive the LNG price will be as long as the product is transported within a critical distance of around 2,000 km. Given this typical pricing characteristics, intra-regional LNG trade is the most likely option.

Gas production in Southeast Asia has more than doubled over the last two decades. Indonesia and Myanmar and, to a lesser extent, Malaysia, will further increase Southeast Asia's gas production until 2035. Total gas production in the region will grow by 30 percent (from 203 Bcm in 2011 to about 260 Bcm in 2035). About three-quarters of the incremental growth is expected to come on stream by 2020.

The ASEAN region is a key exporter of LNG to global markets as well as an increasingly LNG importer. In the case of Indonesia and Malaysia, a mismatch between the geographic locations of their gas resources vis-a-vis rising local demand has created a situation where they are both importers and exporters of LNG. Unnecessary spending, thus, could be avoided by interconnecting the energy markets and improving intra-regional trade. In fact, the rising local demand and limited interconnections among countries in the region have prompted the installation of several LNG regasification terminals in recent years.

Studies indicate that because India is strategically located between the Middle East and the ASEAN and Far East (Japan and Korea) areas, this nation can contribute to developing and nurturing the natural gas market in the region. India’s aggressive offshore gas field acquisition and joint venture plans can increase access to the gas supply and allow long-term, low-cost gas contracts. It can also opt to enter into joint ventures with or acquire liquefaction projects in Indonesia, Malaysia, and Australia. In fact, in early 2014, the Adani Enterprises Ltd. of India bought the world's largest coal port in Queensland, thus potentially increasing the flow of coal for power generation in India.

Moreover, because of India's own burgeoning domestic demand for gas, the nation needs gas-importing facilities such as import terminals and regasification plants. Since India only has a couple of projects related to the regasification plants along with ports, it should still consider joint ventures, equity financing, or other suitable financing mechanisms for developing LNG import facilities in nearby locations. Myanmar, Bangladesh or Thailand, for example, can be linked to India even by surface transport. Asian Highway 2[3] can even be utilised to transport LNG in tankers by land. Because 20 percent of the total supply cost of gas in Asia is currently coming in as shipments, reducing the distance of imported gas can control LNG's landed price.
Thus, India's Look East policy should emphasise:

- How to increase its stake in ASEAN and South Asian regional natural gas exploration licenses;
- How to improve its access to LNG value chain infrastructure development to reduce the operational and shipment cost of LNG; and
- How to increase the supply of alternative sources of gas such as low-cost shale domestically as well as from other locations such as the United States and Canada.

Table 4.4 below lists the planned projects in the LNG value chain in the ASEAN and South Asian regions wherein India may consider taking part in various capacities, be that as technical partner, financial collaborator or even direct acquirer. The list excludes construction projects where an addition of a new partner is not an option.

[3] Asian Highway 2 is the road in the Asian Highway Network running 13,177 km from Batam, Indonesia to Khosravi, Iran and Tanjungpinang, Indonesia to Khosravi, Iran.

Table 4.4: Planned LNG Projects in the Region

Country of Project	Project Name	Capacity (MMTPA)	Year Started	Project Status
Liquefaction				
Indonesia	Abadi FLNG (on Arafura sea)	2.5	n/a	Planned
Malaysia	Rotan FLNG in Sabah	1.5	2016	Planned
Regasification				
Indonesia	Banten FSRU	3.0	-	Planned
	Central Java FSRU	3.0	2016	Planned
Malaysia	Lahad Datu in Sabah	0.8	2016	Planned
	Pengerang in Johor	3.8	2017	Planned
Philippines	Quezon LNG	1.0	-	Planned
	Batangas FSRU	3.8	2017	Planned
Thailand	Ma Ta Phut LNG Expansion	5.0	2014	Planned
Viet Nam	Thi Vai LNG	1.0	2016	Planned
	Binthuan LNG	3.0	2018	Planned
Gas Pipeline				
Myanmar-India-Bangladesh	Gas Pipeline	900 Km total gas trade of 5 Bcm.		Pipeline from the Shwe field off the Bay of Bengal through the Rakhine State in Southern Myanmar, from where it would turn east to enter the Indian state of Tripura. The pipeline would then enter Bangladesh at Brahmanbaria and traverse the country until it exits at Jessore and terminates at the Indian state of West Bengal.

Source: Compiled from reports published by International Gas Union in 2011 and 2013, Wijayatunga and Fernando (2013), ADB (2012) and Gippner (2010), World Bank (2013), The New Age (2013), CIA (2013), Hameed (2011), ADB/ADBI (2009), Rahman, *et al*. (2013), Thant, *et al*. (2013).

Assessing Natural Gas Sector's Investment Demand in ASEAN and South Asia

The earlier section discussed the importance of natural gas in the energy supply of the South and Southeast Asian region, including India. The natural gas market in this region is yet to mature and thus needs huge infrastructural development across the gas value chain covering exploration, extraction, shipment, and distribution.

Two major gas products---piped natural gas (PNG) and liquefied natural gas (LNG) ---have different infrastructure requirements although they are characteristically the same product at the end-user level. Liquefied natural gas is easier to transport across long distances compared to PNG, which needs physical connectivity between producer and consumer. The LNG can be shipped to any parts of the world by tankers. This is the main reason LNG business is growing fast.

However, the LNG business is highly price sensitive in both supply as well as demand side. Once LNG prices increase, consumers immediately react by shifting their fuel use to PNG. At the supply side, on the other hand, if the LNG price falls, investors shy away from investing in new projects due to concerns of increased risk in capital recovery. Therefore, a fine balance is needed to satisfy both consumers as well as investors.

Asia's gas market currently experiences high volatility because efforts in improving its regional gas supply has not caught up with the speed with which demand is increasing. Up until 2013, more than 70 percent of the region's LNG is imported from other parts of the world. At present, China, India, and Japan together consumes more than 45 percent of the world's LNG, but this is expected to increase to up to 70 percent by 2030.

Model Description and Major Assumptions

What then is the future investment demand in the energy sector of the region (including the ASEAN), and of India? Following the principles of market integration, it is assumed that more energy sector cooperation between the sub-regions of South and Southeast Asia (mainly India) will enhance the level of energy trade. It is further assumed that market integration could increase the trade in both PNG and LNG by around 10 percent.

This section aims to estimate a least-cost optimal energy supply system for the region under an improved inter-regional trade, especially on natural gas and utilisable energy (electricity). A bottom-up energy system model (i.e., MESSAGE) is used here to calculate the demand. The Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE) is a multi-region energy system model capable of estimating the least-cost supply option of energy in a long-term manner under different constraints such as climate, resource, and costs.

The model pathways assume a common median demographic projection wherein the global population increases from almost 7 billion today to about 9 billion by the 2050s (UN DESA, 2009). The pathway also assumes a median economic development path, expressed in terms of world GDP, which allows significant development in the 50 or so poorest countries in the world. At the same time, it reflects higher resource productivity as well as demand growth in the richest countries but is dampened by changing consumption patterns and lifestyles. This GDP development path is built on the updated IPCC B2 scenario.

The socioeconomic development pathway chosen in this model is consistent with global aspirations towards a sustainable future that is highly attainable. Global real per-capita income in the study pathway grows at an annual average rate of 2 percent over the next 50 years, but with significant differences in the pace of development across regions.

Final energy use in 2005 was presumed to be 7 GJ to 46 GJ per capita in developing countries and 73 GJ to 219 GJ per capita in developed countries. Meanwhile, GDP per capita is US$671 to US$4,905 for developing countries and US$3,487 to US$40,050 for developed countries. It is further assumed that by 2050, the developing countries' per-capita energy consumption would be around 28 GJ to 50 GJ while that of developed nations would be around 62 GJ to 98 GJ.

The GDP per capita by 2050 is anticipated to be in the range of US$6,000 to US$20,000 for developing countries and between US$24,500 to US$52,000 for developed countries. In terms of final energy consumption intensity (MJ/dollar of GDP), the model assumes that the regions had an intensity of from 3.0 MJ/dollar to 9.8 MJ/dollar of GDP in 2005, which will then drop to 0.9 MJ/dollar to 2.5 MJ/dollar of GDP by 2050.

Model Scenarios

This study has two set of scenarios:
Business as Usual (BAU) scenario: This scenario considers implementation of all existing mid- to long-term plans along with no strict environmental and greenhouse gas (GHG) emissions reduction targets. In terms of macroeconomic drivers, regional GDP growth rates are considered moderate at 5 percent to 6 percent per annum until 2050, and population growth rate is estimated to be around 1 percent per annum. Primary energy consumption in the South and Southeast Asia regions under this scenario is presumed to be 30 GJ to 40 GJ per capita by 2050.

Enhanced Energy Trade (EET) scenario: An increase in energy trade in natural gas, including both PNG and LNG, is assumed. The region is expected to come up with more than 10 to 15 new LNG terminals and liquefaction plants by 2050 to strengthen its LNG exporting capacity. By 2030, the total LNG export capacity will be growing by 10 percent to 15 percent.

In fact, a potential increase in the import and export capacity of coal, oil, and natural gas by 10 percent every 10 years until 2050 and by 1.5 percent of LNG export capacity every year from 2010 to 2050 is assumed. However, since the actual capacity utilisation will start from 2015, the enhanced LNG export for the Southeast Asia region is expected to begin in 2020.

Simulation Results and Findings

Under the EET scenario, the gas sector is assumed to be the second largest area for future investment in the ASEAN region. Majority of the investment goes into new port capacity addition and construction of liquefaction units. The region is also investing heavily in regasification plants to meet the increasing energy demand that accompany economic growth. In terms of LNG value chain costs, liquefaction is one of the most costly activities, followed by exploration, shipping, and regasification. Thus, majority of the sectoral investments amounting to US$10 billion to US$12 billion per annum by 2040 would go into developing the liquefaction capacity and LNG shipping infrastructure. Figures 4.7(a) and 4.7(b) illustrate the expected investment scale in the region by 2040.

Figure 4.7(a): Investment Demand in Energy Sector in ASEAN Region (in US$@ 2005)

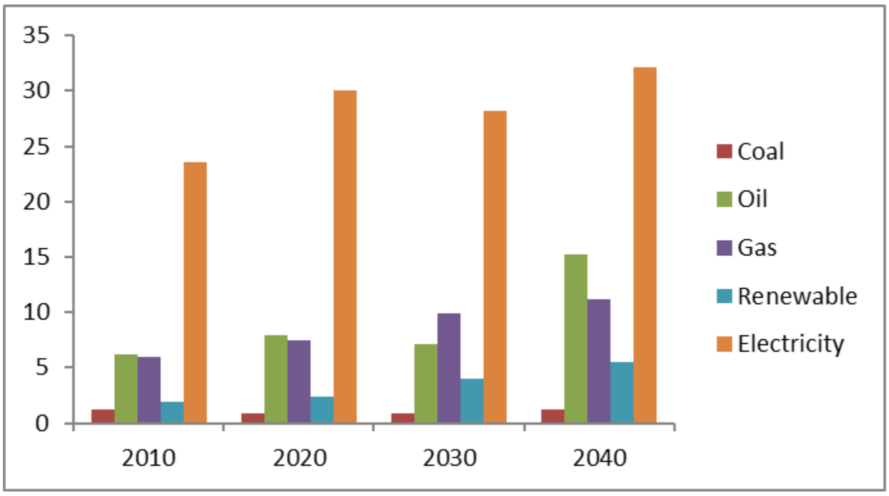
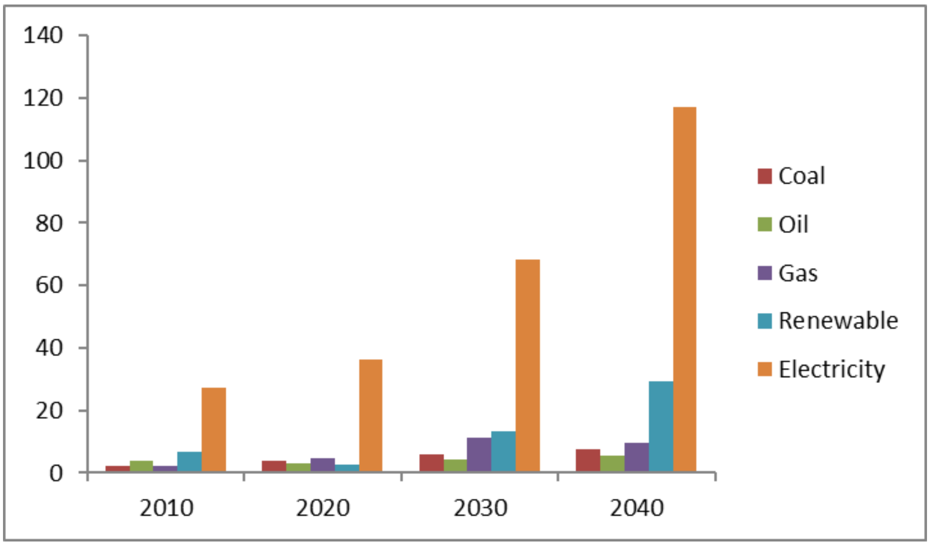


Figure 4.7(b): Investment Demand in Energy Sector in India and South Asia Region (in US$@ 2005)



Source: Model generated, authors' estimated.

India and other South Asian countries are expected to invest more in the electricity sector than in other energy sectors such as natural gas, coal, and oil. India will add 150,000 MW of thermal generation by 2017, of which more than 30 percent of the capacity added is on gas-based generation. However, investments will also focus on constructing LNG terminal facilities, regasification plants, and pipelines that will transfer gas to destination points. Given the pattern of future investments, India is anticipated to continue importing fuel so that its domestic power sector supply can support the bigger capacities of its thermal power stations. The country has already been increasing its coal and LNG imports year-on-year to meet the demand of the high efficiency power plants.

In the ASEAN region, majority of the investment is expected to be in the electricity sector, followed by the gas sector. However, the region's total investment in the gas sector is higher than that of India and other South Asian countries mainly because of the former's heavy investments in new gas field exploration and gasification plants.

Cost Comparison between Pipeline and LNG

Since 2010, the LNG capital cost has been rising rapidly across the value chain and across geographical locations. The highest cost escalation has been observed in the Asian region partly due to foreign exchange rate variations. Asia's capital expenditures (CAPEX) for LNG liquefaction has gone up to US$900/ton in 2013 compared to US$400/ton in 2010. This is further projected to go as high as US$1,400/ton by 2020. Almost all liquefaction projects under construction in this region are facing very high cost overruns. Thus, investors worry about this market's future growth in spite of the continuous demand for LNG for the next two decades.

In terms of regasification projects, capital cost is likewise rapidly increasing in Asia more than in the rest of the world. Onshore regasification projects (including storage, regasification, piping) cost around US$187/ton in 2013 compared to US$145/ton in 2011. By 2020, such project cost could escalate up to US$220/ton. This is a huge jump if one where to compare with the 2004 on-shore regasification CAPEX of below US$100/ton. On the other hand, as an LNG importer, a nation has a number of technological options with varied cost structures to choose from. For example, floating LNG terminals are relatively less expensive that on-shore units (US$135 /ton).

Strategic Importance of Myanmar

Myanmar is strategic in India's bid to secure its energy supply. Given the country's existing and potential gas availability in the mid- to long-term, Myanmar can supply to India provided the latter develops the required infrastructure and makes the needed resources available.

Role of Myanmar in Regional Energy Trade

Located between two economic giants China and India, which together is home to 2.5 billion people, Myanmar bridges South and East Asia. Myanmar produces 2 MTOE per annum of surplus that can be exported. Its total energy export amounted to 8.6 MTOE in 2011, which was roughly more than half of its total primary energy supply. That same year, it exported to Thailand 36 Bcm of pipeline natural gas out of its 700 Bcm of total gas reserve.

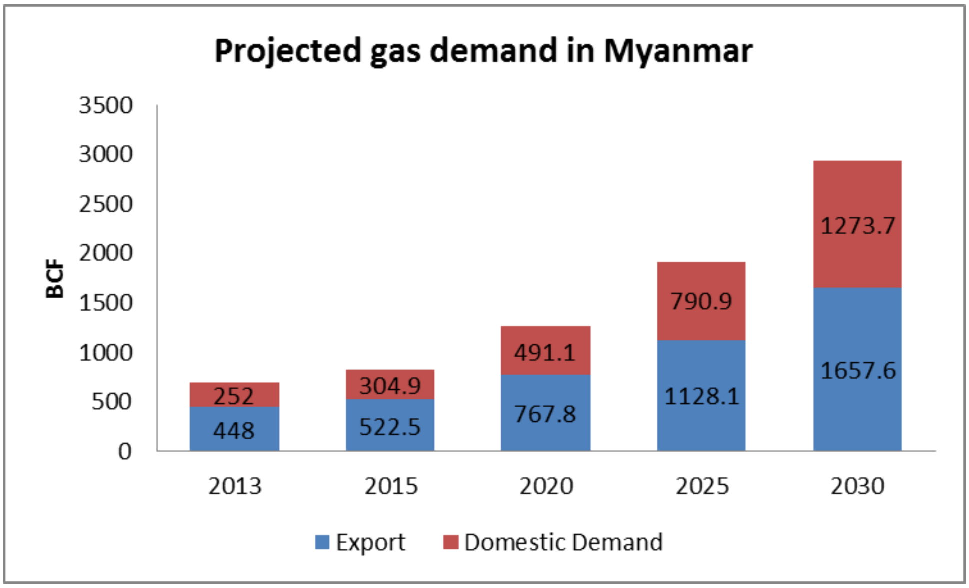
China, too, is arranging a major deal with Myanmar by investing US$4.8 billion into the Shwe Gas project. This will be the single largest gas field in Southeast Asia with a total capacity of 150 Bcm. An 850-km pipeline is under construction to get this gas into Yunnan province. Myanmar's Ministry of Energy has further opened 11 shallow and 19 deep water blocks through competitive bidding.

Reserves and Availability of Myanmar Gas

Until recently, Myanmar’s proven gas reserve is around 12 Tcf (or 12,000 Bcf), mostly coming from two blocks in the Shwe gas fields. It currently produces around 1.2 Bcf of gas per day. Domestic demand for gas is still lower than that of its exports due to the low energy demand from its domestic industries and households.

As of 2013, Myanmar’s domestic gas demand is around 0.7 Bcf per day (or 252 Bcf per year) compared to 448 Bcf of annual exports. Its gas surplus may continue for another couple of decades even with a steady growth in domestic demand, provided the gas production remains stable. Annual domestic demand will grow at 10 percent per annum while export demand will rise at 8 percent until 2030. At these growth rates, Myanmar’s total consumption will be around 2,800 Bcf by 2030. Figure 4.8 shows Myanmar's projections on domestic and export gas demand until 2030. This statistics further confirms that Myanmar will continue to be an energy exporter in the South Asian region.

Figure 4.8: Projected Domestic and Export Gas Demand of Myanmar



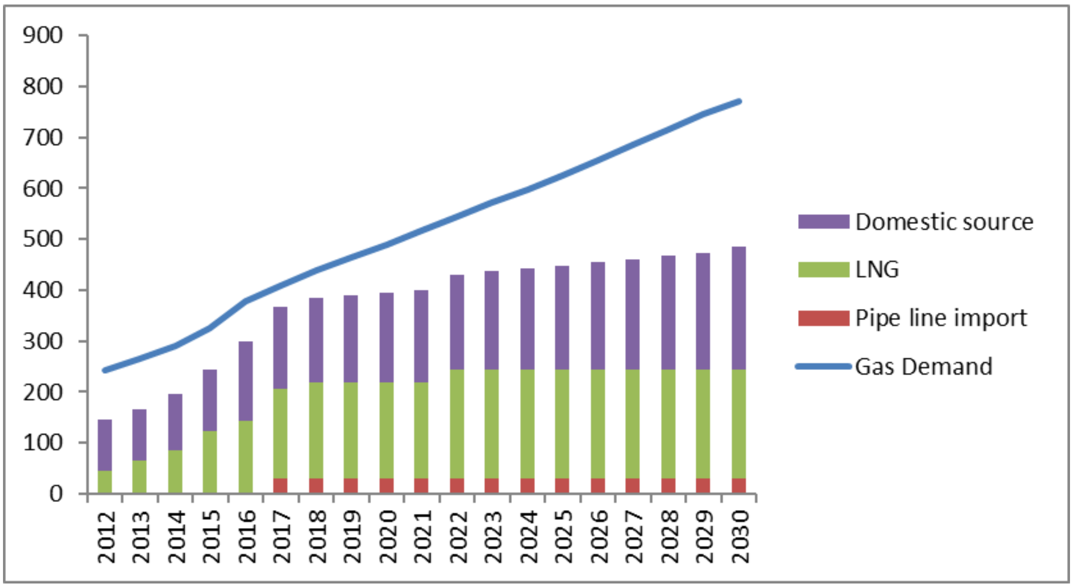
Source: Authors' estimates using data from ADB report on Country Partnership Strategy 2012-14, BP Energy Statistics 2013.

Out of 12 Tcf of reserves, Myanmar has already committed majority of its share to China and Thailand under several long-term contracts. There is a very limited resource available for other countries such as India. Nevertheless, Myanmar has 80 Tcf of potential reserves that are yet to be contracted. The Myanmar government, with its current level of technical and financial capacity, is not yet in a position to convert these potential reserves into proven reserves. India, thus, could opt to be a potential technical and financial partner of Myanmar on this regard.

Scope of India-Myanmar Gas Trade

India’s long-term natural gas demand has been increasing rapidly compared to its domestic gas supply. Such demand-and-supply gap has widened exponentially over time. By 2030, India’s gas supply and demand gap will reach up to 280 MMSCMD, or around 35 percent of the country's total gas demand. Figure 4.9 shows the supply and demand for India's domestic and imported gas.

Figure 4.9: Indian Gas Supply and Demand Condition by 2030 (in MMSCMD)

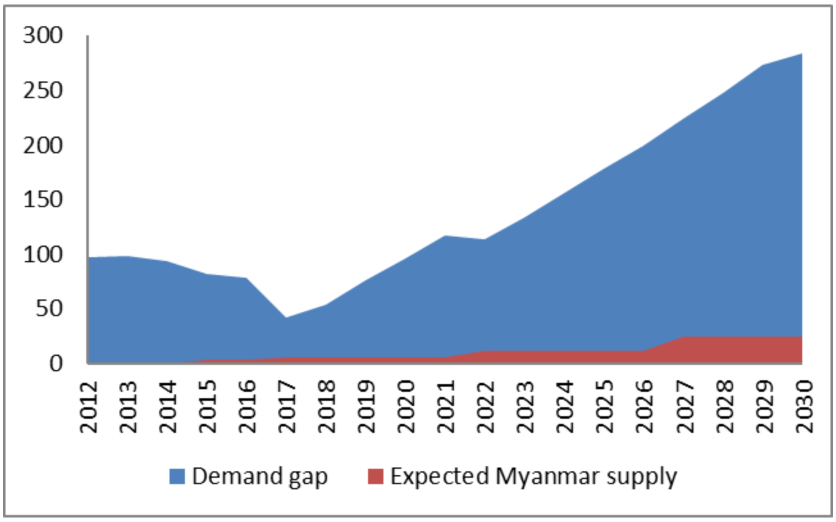


Source: Authors estimated using data from published documents of Ministry of Oil and Natural Gas, Govt. of India

To supplement its domestic gas exploration, India also sources its gas from overseas. Currently, India imports around 16 Bcm gas from Qatar, which is around 78 percent of its total import. Up until 2012, Myanmar was not being considered as a source of gas for India. However, Myanmar's potential as a supplier of relatively low-cost gas is now acknowledged.

Although proposed for quite while now, the Myanmar-Bangladesh-India gas pipeline has not materialised due to various political issues among countries. If this plan eventually pushes through, Myanmar can supply 24 MMSCMD by 2040. While the amount mentioned is not significant enough to cover India's requirement, it is just the same a secured supply for India provided proper infrastructure is in place. Figure 4.10 shows the possible contribution of Myanmar gas from the A-1 gas field of the Shwe Project.

Figure 4.10: Expected Myanmar Gas Supply to India (in MMSCMD)

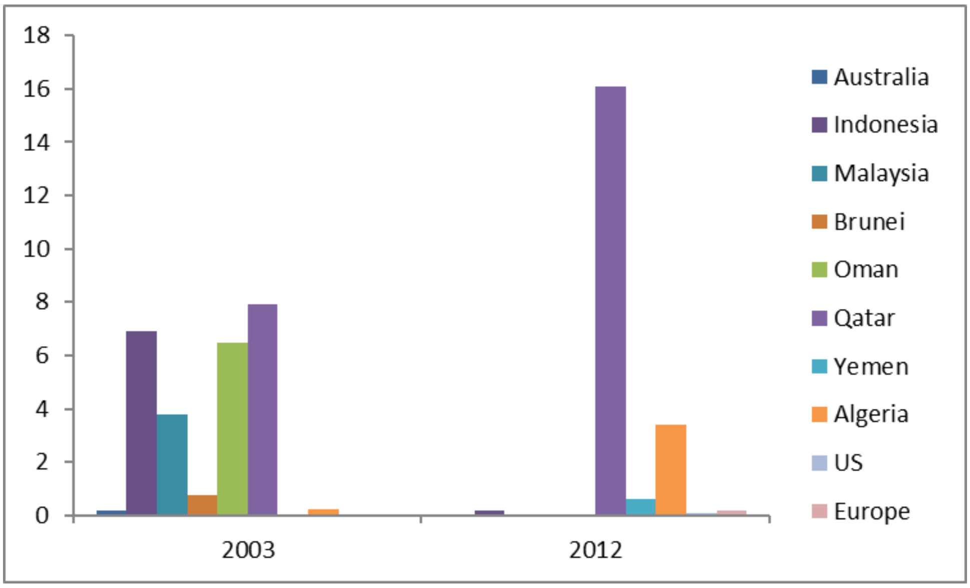


Source: Author estimated using data from Ministry of Oil & NG, Government of India; Ministry of Energy, Government of Myanmar 2013.

From 2003 to 2013, India changed its list of gas sourcing countries mostly from the ASEAN region to the Middle East. It now imports gas from the Middle East (Qatar, Yemen) in bulk and pays almost US$16 to US$17 per MMBtu. This price is primarily linked to the international crude oil price and Japan crude cocktail.

Figure 4.11 below shows how India shifted its supply base from Eastern counties to the Middle East in a rapid manner.

Figure 4.11: India's Historical Gas Supply Condition



Source: Authors estimated using data from BP Energy Statistics, 2013.

This figure further demonstrates India's gradual move towards riskier supply chains by abandoning its ASEAN sources. To achieve more energy security, India needs to revive its tie-up with countries such as Bangladesh, Myanmar, and Thailand. Although China is much ahead of India in terms of establishing a relationship with Myanmar, India could still get into the picture given that Myanmar still has 80 Tcf future gas potential for reserve.

Myanmar's Position as Natural Gas Exporter to India

Based on the available natural gas so far contracted to Indian companies (mainly in A-1 block), Myanmar can provide around 6-8 MMSCMD. This amount is very small compared to India's total demand. India must therefore explore other indirect options to enhance its stake in Myanmar's gas in both mid- to long-term periods.

This study used a multi-criteria analysis on Myanmar's energy sector to understand the pros and cons of its long-term gas development project with India. The analysis is based on the following criteria: (1) Technical limitation of Myanmar's gas supply; (2) Long-term availability of excess energy; (3) Myanmar's geopolitical situation; (4) Myanmar's socio-economic situation due to energy cooperation; and (5) Myanmar's investment environment and energy pricing. Each indicator has been evaluated against the primary objective of creating an environment that will enable India to source natural gas from Myanmar. This exercise mainly aims to identify the factors that can hinder lndia's bid to increase its long-term gas supply contract with Myanmar.

Issue 1: Technical limitation of gas supply

One limitation of access to Myanmar's gas supply is linked to its poor technical capacity to convert resources into reserves. The country has an estimated reserve of 12 Tcf compared to production of only 1.2 Bcf/day only. Its poor infrastructure to carry gas from remote gas fields to the demand centres is another factor to hurdle if it were to increase its gas production. For example, the Yadana gas pipeline is supposed to provide 200 Mft^3/day to Yangon but, in practice, is supplying only 30 Mft3/day due to its obsolete and poorly maintained pipeline infrastructure. Also, Myanmar already has several long-term export contracts; meaning, only a very limited amount of gas is left for new contracts. During 2010-2011, out of 10,000 KTOE of natural gas production, Myanmar exported around 8,900 KTOE.

These existing conditions in Myanmar can be considered as opportunities for India to provide technical assistance, on a success fee basis (i.e., percentage of saved or recovered gas), in the areas of performance improvement, loss reduction and recovery, and gas transportation, as well as in building new infrastructure for the gas industry.

Issue 2: Long-term availability of excess energy

Increasing Myanmar's electrification ratio from the current 26 percent to at least 80 percent by 2030 could significantly reduce its capacity to export energy. The existing per-capita electricity consumption is around 100 Kwh/annum---far below the world average of 600 Kwh/annum. However, because the country would have around 70 million people by 2030, it will by then need to be supplied around 42,000 Gwh of electricity. Aside from the higher population, the rising energy demand from its industrial sector would also reduce the potential to export energy. By 2015, Myanmar's industrial contribution to GDP will jump to 32 percent as compared to 26 percent in 2010.

Thus, Myanmar's increasing domestic demand for natural gas may significantly hamper India’s aspiration to enter into big-volume contracts in the future assuming no new resources are discovered in the interim.

Issue 3: Myanmar’s geopolitical situation

Although India’s Look East Policy was in place for a couple of decades, the India-ASEAN linkage via Myanmar did not prosper. Neither did the Bay of Bengal Initiative for Multi-Sectoral Technical and Economic Cooperation (BIMSTEC) work as per expectations. Meanwhile, China (via its Go West Policy) created long-term agreements with Myanmar to develop their gas fields and import gas via pipelines. The Myanmar-China gas pipeline connecting Shwe gas field in Myanmar can export 1.2 Bcf gas per day to China, which is more than 100 percent of its current capacity of 500 Mcf/day. Also, almost all future large-scale hydro power projects in Myanmar are funded and supported by China.

Thus, by 2020, more than 75 percent of Myanmar's gas is expected to be exported to China. This skewed relationship favouring China in terms of developing, managing and maintaining Myanmar's burgeoning energy sector is one of the biggest hurdle to India's bid to establish its own energy trade relationship.

Issue 4: Myanmar’s socio-economic situation

Large-scale, international energy infrastructure projects may not necessarily benefit the Myanmar's local people. Kyaukphyu, which is at the southern end of the Myanmar-China gas pipeline of the Shwe project, has not received the required benefits and development promised by project developers, including the local government. While the Chinese authority has provided compensation to the local government, this was not distributed effectively among the beneficiaries, leaving the locals unhappy.

Also, Myanmar has no standard environmental regulation to mitigate any ecological and environmental damage brought by infrastructure development. Neither is there a rehabilitation policy for displaced locals. Myanmar also lacks a skilled technical workforce among its locals, who can deal with the complex technology involved in gas extraction, transportation and use.

Such socio-economic situation is an area of opportunity for India to establish soft linkages with the Myanmar government and, in the long run, to gain access to new gas fields that are now at resource stage. India can opt to provide technical assistance in sustainable gas exploration, establish technical training institutes, or build capacity to conduct environmental impact assessments as well as conduct impact assessment of new projects. These efforts may not only help Myanmar improve the projects' operational efficiency but also give the country the ability to discern which new projects may have an adverse environmental and ecological impact. Such assistance can improve their bilateral relations and India's access to new projects in the future.

Issue 5: Myanmar’s investment environment

Myanmar still has a lot of room to strengthen its foreign direct investments (FDI) policies on energy cooperation. Most of its FDIs in the energy sector are joint ventures on onshore and offshore blocks, but these have not generated enough value add to the domestic market in terms of knowledge and technology development. International companies are more inclined towards individual benefits rather than following a comprehensive development plan designed to equally benefit local partners.

Myanmar’s financial regulatory system, including the insurance and legal system (i.e., dispute settlement), are also not sophisticated enough to handle massive foreign investments in the domestic market. In fact, its financial market is still at a nascent stage of development and demands huge amount of improvements in all spheres. Although Chinese investment in Myanmar's energy sector already reached around US$12 billion by 2013 (IHLO, 2013)---which comprises 40 percent of Myanmar's total FDI---the economy-wide impact of such investments are not apparent yet due to several reasons. One important explanation could be the divergence between the FDI proposal and Myanmar’s domestic requirement and social structure. For instance, several instances of civil unrests were reported in and around various energy projects funded by international institutions. India can consider this as an opportunity for it to take part in reforming Myanmar's financial sector, especially in making its regulatory and legal systems robust and, through Myanmar, establishing deeper connection with the ASEAN nations down the line.

Issue 6: Myanmar’s energy pricing

Myanmar’s energy price is one of the lowest in Asia. In 2011, official electricity charges in Yangon were 12 cents per kWh for foreigners and 75 kyat (9 cents) for offices; however, the average price actually paid by the end of the year was only 5 cents/kWh, or 35 kyat. These prices fall far below the cost of producing electricity.

If Myanmar could supply additional gas in the regional market, this would be procured by countries in both South Asia and Southeast Asia. Furthermore, assuming trade in natural gas and LNG does increase, the region is expected to come up with 11 to 15 new LNG terminals and liquefaction plants by 2050. By 2030, total LNG export capacity in the region is expected to grow by 10 percent to 15 percent.

Energy price affects the operational efficiency and long-term sustainability of the energy supply. Subsidised energy, meanwhile, not only encourages wastage of energy but decreases resources' rent costs, too, which then ultimately exhausts the resource at a faster rate. India could consider this as an opportunity to help build Myanmar's capacity to reform the pricing system for energy resources (including natural gas) so as to extend the long-run availability of gas. Such cooperation in price reforms can likewise help India make the most out of the ASEAN-India energy market integration via Myanmar.

In all these, one can therefore conclude that while the volume of Myanmar's gas supply to India may be insignificant in the short run, it is to India's advantage to set up strong linkages with this neighbouring country. Myanmar, after all, could be India's gateway to the ASEAN and Far East trade (including of energy commodities) in the near future. It can indirectly give India a foothold into the region's supply of LNG. India should proactively take advantage of its geographical proximity to the largest offshore gas field (Shwe Project) on the Bay of Bengal, Myanmar and jointly explore the project's future blocks.

Redefining India's Look East Policy in the Context of the Energy Market Integration

India initiated the Look East Policy in the 1990s to strengthen its relationship with ASEAN countries. In 1997, a sub-regional economic grouping called BIST-EC consisting of Bangladesh, India, Sri Lanka, and Thailand was established to strengthen the Look East Policy. Later, the group was renamed BIMSTEC with the addition of Myanmar, Bhutan, and Nepal. This group aims to create an enabling environment for rapid economic development through cooperation projects in trade, investment and industry, technology, human resource development, tourism, agriculture, energy, infrastructure, and transportation.

The Look East Policy eventually gave India the opportunity to re-engage with its eastern neighbours and to gradually emerge as a significant player in the strategic dynamics within the region, which is centred on a rising China. Economically, India's trade with the ASEAN grew immensely: From US$2.3 billion in 1991-1992 to US$45.34 billion in 2008-2009. Singapore stood out as India's largest trading partner in the ASEAN, followed by Malaysia and Indonesia.

The pace of economic reforms in India also saw ties being further forged with East Asian neighbours. In the second phase of the Look East Policy, a Free Trade Agreement (FTA) was signed. Considered the highlight of the policy is the signing of the India-ASEAN Free Trade Agreement on 13th August 2009 in Bangkok. The agreement focused on trade-in-goods and did not include software and information technology. Two-way trades between India and the ASEAN reached US$47 billion in 2008, as compared to the earlier estimate of US$10 billion.

Some initiatives under the Look East Policy strengthened India's infrastructure for oil and natural gas imports from neighbouring countries. One project was the construction of the 165-km Indo-Myanmar Friendship road connecting Tamu and Kalaymiyo-Kalewa in February 2001. Other important projects are the Myanmar–India-Bangladesh gas and/or oil pipeline, and Tamanthi Hydroelectricity project. Two agreements related to oil and natural gas infrastructure development in the second phase of the program are the India-Myanmar Bilateral ties (2011) and the India–Viet Nam pacts (2011).

India-Myanmar Bilateral Ties in 2011: On 14th October 2011, India's prime minister, Dr. Manmohan Singh and visiting president of Myanmar, Mr. U. Thein Sein, held talks in New Delhi, where India sought to booster its ties with Myanmar by pledging an additional US$500 million as loans. The state heads agreed to examine the feasibility of establishing railway links and to speed up work on two hydroelectric power projects in Myanmar. They also arranged to tighten their cooperation in the oil and natural gas sectors.

India–Viet Nam Pacts in 2011: On 12th October 2011, India and Viet Nam signed six agreements that included a pact to promote oil exploration in the South China Sea. However, China objected to India exploring oil in the South China Sea, claiming that it was a part of China. India and Viet Nam rejected China's claim, pointing out that as per the United Nations, the blocks belong to Viet Nam.

In the field of security cooperation, the two nations instituted mechanisms for biennial dialogues on security issues. They also decided to increase the trade target to US$7 billion by 2015 from the present level of US$2.7 billion.

Based on the above multi-criteria assessment of Myanmar's role in India's bid to further energy sector cooperation with the ASEAN and other South Asian countries, the Look East Policy should focus on two aspects:

- **Soft linkages between countries**: India has immense capacity and resources to assist, guide, develop and reform neighbouring countries in such fields as technical capacity, banking and finance, and institutional capacity in the energy sector. The Look East Policy should therefore emphasise the need for clear and quantifiable objectives on soft linkages that are related to regional energy cooperation and integrated market development.
- **Hard linkages between countries**: Now that India is in the process of strengthening its market linkages with the ASEAN and other South Asian countries, especially after its new government took over in May 2014, its Look East program should now redefine policies in the energy sector in a

quantifiable manner. Such policies should emphasise the issues surrounding targeted acquisition of international gas exploration licences, increasing joint ventures in gas exploration, cross-border energy infrastructure development targets, etc.

Conclusions

Beyond partly providing a solution to India's gas demand in the short-run, Myanmar is key in linking India with the ASEAN energy market. India, therefore, needs to utilise its existing Look East Policy to enhance the scope of further cooperation with the ASEAN countries, including Myanmar.
Myanmar, on the other hand, can help promote South and Southeast Asian energy cooperation by improving the following areas:

- Myanmar should consider providing the needed gas supply to close the gap with the regional market's demand. This supply could be in the tune of 3 Tcf to 4 Tcf by 2030 after meeting all domestic and existing long-term export contracts.
- Myanmar needs to invest in enhancing its resource recovery capacity in the gas sector and to improve the efficiency of existing gas infrastructure such as the pipeline flow density.
- There is a need to upgrade Myanmar's gas-based power plants that are still using single open-cycle systems and consuming more than 300 percent extra gas to produce the same amount of electricity by closed-cycle system. This will help save a substantial amount of gas for either its domestic use or for export.

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CHAPTER 5

The Welfare Impacts of Price Equalisation in Energy Market Integration

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This research analyses the welfare impact of price equalisation in energy product prices in ASEAN. For this analysis, an econometric model and the Compensating and Equivalent Variation under Linear Expenditure System (CV and EV under LES) are applied. This research uses data import value and price of energy products under SITC 3 digits. Some conclusions are drawn. First, the price equalisation process occurs until a certain level of price variation for all energy products is reached as variation coefficients converge monotonically and in oscillatory manner toward a positive steady state in ASEAN. Second, the simulation using the average annual increases of energy prices for 1980-2012 shows that price equalisation will bring positive total welfare (both direct and indirect) impacts of US$77,06 trillion (CV) or US$81,32 trillion (EV) per year for ASEAN.

Keywords: energy products, price equalisation, welfare impact, energy market integration.
JEL Classification: Q04, F3, I3.

Introduction

The first solid effort toward regionalism in the East Asian region was the Association of South East Asian Nation (ASEAN) Free Trade Area (AFTA) launched in 1992 by the ASEAN. The AFTA aims to promote further cooperation in the region's economic growth by accelerating the liberalisation of intra-ASEAN trade and investment after the success of the ASEAN in maintaining international and political stability in the region. For 2015, ASEAN countries are eager to establish a more advanced level of economic integration—the ASEAN Economic Community (AEC)—through the "ASEAN way", which is a little bit different from the theoretical stages of economic integration by Balassa (1961), i.e., Free Trade Area (FTA), Customs Union (CU), Common Market (CM), European Union (EU), and Complete Economic Integration (CEI). With the free movements of skilled labour and capital, the AEC has parallel characteristics with the Common Market (CM) in the theoretical successive stages of economic integration. The issue of rule of origin (ROO) may occur in the AEC since individual members still maintain their own tariffs against non-member countries. Consequently, the flow of production factors (capital and labour), trade diversion, and trade creation could not be optimised in the AEC due to the absence of common external tariffs. However, with the "ASEAN way", the governments of ASEAN member countries still want to realise the AEC in 2015 as scheduled. Energy is needed in supporting distribution, consumption, and production activities in the AEC, thus, the community needs to consider the ASEAN Energy Market Integration (AEMI).

ASEAN is one of the fastest-growing economic regions in the world and has a fast- rising energy demand driven by both economic and demographic growth. The region's economic and population growth had resulted in a consequential increase in final energy consumption. With the assumed gross domestic product (GDP) growth rate of 5.2 percent per annum from 2007 to 2030, the final energy consumption was estimated to increase to 427 million tons of oil equivalent (MTOE) in 2010 and grow to 1,018 MTOE in 2030 at an average annual rate of 4.4 percent (3rd ASEAN Energy Outlook, 2011). This growth is very much higher than the world's average growth rate of 1.4 percent per year in primary energy demand over 2008-2035 (IEA World Energy Outlook, 2010). In view of the high economic growth and need of energy supply, the challenge to ensure a secure supply of energy is a prevailing concern for the AEC.

This research basically aims to answer two main research questions. *First*, has price equalisation in energy product prices occurred in the ASEAN? Theoretically, under the assumption of perfect competition, regionalism and market integration in ASEAN postulates the existence of energy price equalisation. *Second*, how do the potential welfare impacts of the ASEAN affect energy market integration?

Literature Review

Regional economic cooperation is an essential locomotive for raising the economic development of ASEAN member states, to enable them to utilise efficiently their full economic potential resources. Energy infrastructure is, therefore, a key pillar supporting the participating countries' drive for development through regional cooperation (Chang, *et al*., 2013). Several factors are driving the move toward regional energy cooperation. The uneven distribution of energy resources among member countries, suboptimal level of energy interrelationships, least-cost solutions to energy constraints, and rocketing prices of global energy boost the attractiveness of large hydropower project options (CAREC, 2008).

Theoretical perspective provides a wide picture of the role of energy market integration (EMI) as a building block of regionalism, especially in economic development sector. However, evidence from empirical studies is still limited. Among the few, Bhattacharya and Kojima (2008, 2010) show support with their findings that there are more benefits from EMI than the costs required. The linking of electricity grids can create both economic and environmental benefits. In addition, Park (2000) concludes that free trade agreement, in which energy products included, may bring positive economic impact to member countries within the region. Lee, *et al.* (2009) and Chang, *et al.* (2013) evaluate the potential effects of the AEC on economic welfare, trade flows, and sectoral output of the member states using a dynamic computable general equilibrium (CGE) model and Global Trade Analysis Project (GTAP) model, respectively. The consequence of bearing arm-length characteristics is near-complement to capital in the short run, but a substitute for capital in the long run. A similar suggestion came from Lee and Plummer (2010).

Sheng and Shi (2011) offer the economic convergence analysis (including both the σ- convergence and β-convergence approaches) to scrutinise the impact of EMI across countries with emphasis on East Asian countries between 1960 and 2008. Results show that in addition to trade, an integrated energy market may help to reduce economic development gaps among countries and accelerate the efforts for the least developing countries' (LDCs) income per capita to catch up. The positive impact of energy trade facilitation may play a more important role for the EU and the North American Free Trade Area (NAFTA) countries than for the East Asian countries. The study also finds that investment and capacity building may help to facilitate the catch-up and promote economic convergence across countries.

In addition to the previous study, Sheng and Shi (2012) observe that countries with relatively higher EMI level have, on average, higher energy consumption per capita than countries with a relatively lower EMI level. This implies that EMI (or its representing institutional arrangement) is an important factor affecting the relationship between energy consumption and income and price. Thus, EMI can help reduce such a pressure by improving the domestic energy supply and reducing the price elasticity. Yu (2011) takes a slightly different design in his study. It aims to build up an index system by using the principal component analysis approach. This paper provides such information by ranking the extent of EMI for 16 East Asian countries, including the ASEAN 10 countries, China, Japan, Korea, India, Australia, and New Zealand. Moreover, in this paper he infers that a further integrated energy market is good for each country. Countries in East Asia area should try every effort to foster their EMI. According to Shi and Kimura (2010), the next steps for further EMI in the region lie in three areas: (1) regional agreements on energy trade and investment, (2) energy infrastructure development and national energy market liberalisation, and (3) energy pricing reform and fossil fuel subsidies. Due to disparities in the level of economic development across countries, each country will have different abilities to participate in each dimension.

Methodology

Energy Products

This research applies the definition of “energy products” based on the Standard International Trade Classification (SITC). Under SITC, products are classified according to (a) the materials used in production, (b) the processing stage, (c) market practice and uses of the products, (d) the importance of the commodities in terms of world trade, and (e) technological changes. SITC is categorised as follows:

- *food, drinks and tobacco* (Sections 0 and 1 - including live animals),
- *raw materials* (Sections 2 and 4),
- ***energy products* (Section 3),**
- *chemicals* (Section 5),
- *machinery and transport equipment* (Section 7), and
- *other manufactured goods* (Sections 6 and 8).

This paper uses the 3-digit SITC Revision 2 and focuses on energy products, i.e., SITC Section 3.

Variation Coefficient and Econometric Model

Since the domestic energy market in ASEAN countries are commonly distorted or intervened by the government as one of the administrated goods. For example, with subsidy, energy prices do not obviously reflect the efficient competitive international market prices. Energy product prices vary among ASEAN countries. This paper uses variation coefficient to see the discrepancy of energy product prices, which is formulated as follows:

$$VC_i = \frac{\sqrt{\sum_{j=1}^{n}(P_{ij}-\bar{P}_i)^2 / (n-1)}}{\bar{P}_i} \qquad (1)$$

Where VC_i is variation coefficient of energy product i prices
P_i is energy product i prices
j is country
$\bar{P}_i$ is average of energy product i prices

The smaller the VC, the less variation exists in energy product prices among ASEAN countries. In contrast, the higher the VC, the more variation exists in energy product prices among ASEAN countries. In an extreme situation, VC equals zero (0); this implies that there are no price differences of energy products among ASEAN countries. To examine the existence of price equalisation, the simple autoregressive (AR[1]) model is applied as a representative of the first order linear autonomous difference equation:

$$VC_{i,t} = \beta_1 + \beta_2 VC_{i,t-1} + \varepsilon_{i,t} \qquad (2)$$

By looking at values and magnitude of β_1 and β_2, it is possible to examine whether energy product prices become more equal (less variation) or less equal (more variation) in ASEAN countries.

The long-term equilibrium (steady state) VC_i is formulated as $SS = \frac{\beta_1}{1-\beta_2}$. Therefore, if there is equal price in the long run CV=0, then β_1 must be equal to 0. To investigate the process of price equalisation toward long-run equilibrium (steady state), this can be seen in β_2 (Hoy, *et al.*, 1996):

If $-1 < \beta_2 < 0$, oscillatory converge toward long-run equilibrium (steady state), there is price equalisation.

If $0 < \beta_2 < 1$, monotonically converge toward long-run equilibrium (steady state), there is price equalisation.

If $\beta_2 \leq -1 \ or \ \beta_2 \geq 1$, diverge toward long-run equilibrium (steady state), there is no price equalisation.

This research uses import prices of energy products, which are defined as the value divided by quantity of imported energy products.

Welfare Impact of Price Equalisation in Energy Market Integration

This research will simulate the potential welfare impact of price equalisation in energy due to the AEMI. The welfare impact analysis in this research is mainly derived from the country consumption (import) pattern of energy and other products. Theoretically, a country demand for goods and services is a function of prices and income (by definition of Marshallian demand function). Therefore, some changes in income and prices of goods and services will directly affect the number of goods and services and indirectly affect the welfare (Mas-Colell *et al.*, 1995). It is assumed that country a utility function follows the more general Cobb-Douglas. Stone (1954) made the first attempt to estimate a system equation explicitly by incorporating the budget constraint, namely the Linear Expenditure System (LES). The individual country's preferences defined on *n* goods are characterised by a utility function of the Cobb-Douglas form. Klein and Rubin (1948) formulated the LES as the most general linear formulation in prices and income satisfying the budget constraint, homogeneity, and Slutsky symmetry. Basically, Samuelson (1948) and Geary (1950), derived that the LES represent the utility function, as follows:

$$U(x_1 \cdots\cdots\cdots x_n) = \left(x_1 - x_1^o\right)^{\alpha_1}\left(x_2 - x_2^o\right)^{\alpha_2}\left(x_3 - x_3^o\right)^{\alpha_3} \cdots\cdots\cdots \left(x_n - x_n^o\right)^{\alpha_n}$$

In brief, it can be expressed as:

$$U(x_i) = \prod_{i=1}^{n}\left(x_i - x_i^o\right)^{\alpha_i} \qquad (3)$$

Where:

$\sum_{i=1}^{n} \alpha_i = 1$

$x_i - x_i^o > 0$

$0<\alpha_i<1$

Π is product operator

x_i is consumption of commodity *i*

x_i^o and α_i are the parameters of the utility function

x_i^o is minimum quantity of commodity *i* consumed

$i \in [1,2,3 \ldots\ldots. n]$

The individual country problem is to choose x_i that can maximise its utility $U(x_i)$ subject to its budget constraint. Therefore, the optimal choice of x_i is obtained as a solution to the constrained optimisation problem as follows:

$$\max_{x_i} \; U(x_i) = \prod_{i=1}^{n} \left(x_i - x_i^{o}\right)^{\alpha_i} \qquad (4)$$

Subject to:

$$\mathbf{PX} \leq M$$

To solve the problem, the Lagrange method can be applied. The Lagrange formula for this problem is:

$$\max_{x_i} \; \Omega = U(x_i) = \prod_{i=1}^{n} \left(x_i - x_i^{o}\right)^{\alpha_i} + \lambda(M - PX) \qquad (5)$$

Where: λ is the Lagrange multiplier. It is interpreted as the marginal utility of income showing how much the individual country's utility will increase if the individual country's income *M* is increased by \$1. The Marshallian (uncompensated) demand function for commodity x_i can be found through:

$$x_i = x_i^{o} + \frac{\alpha_i \left(M - \sum_{j=1}^{n} p_j x_j^{o} \right)}{p_i \sum_{i=1}^{n} \alpha_i} \text{ for all i and j}$$

(6)

Where: $i \in (1,2,\ldots\ldots.n)$

$j \in (1,2,\ldots\ldots.n)$

A restriction that the sum of parameters α_i equals to one, $\sum_{i=1}^{n} \alpha_i = 1$, is applied thus the equation (7) becomes:

$$x_i = x_i^{o} + \frac{\alpha_i \left(M - \sum_{j=1}^{n} p_j x_j^{o} \right)}{p_i} \text{ for all i and j} \qquad (7)$$

Equation (10) can be also reflected as the Linear Expenditure System, thus,

$$p_i x_i = p_i x_i^{o} + \alpha_i \left(M - \sum_{j=1}^{n} p_j x_j^{o} \right) \text{for all i and j} \qquad (8)$$

In the context of Linear Expenditure System (LES), the Equivalent Variation (EV) and Compensating Variation (CV) is formulated as follows (Widodo, 2006):

$$EV = \left(\prod_{i=1}^{n} \left(\frac{p_i^o}{p_i^{'}} \right)^{\alpha_i} - 1 \right) M^o - \prod_{i=1}^{n} \left(\frac{p_i^o}{p_i^{'}} \right)^{\alpha_i} \sum_{i=1}^{n} p_i^{'} x_i^o + \sum_{i=1}^{n} p_i^o x_i^o + \left(M^{'} - M^o \right) \tag{9}$$

$$CV = \left(1 - \prod_{i=1}^{n} \left(\frac{p_i^{'}}{p_i^o} \right)^{\alpha_i} \right) M^o - \sum_{i=1}^{n} p_i^{'} x_i^o + \prod_{i=1}^{n} \left(\frac{p_i^{'}}{p_i^o} \right)^{\alpha_i} \sum_{i=1}^{n} p_i^o x_i^o + \left(M^{'} - M^o \right) \tag{10}$$

for all *i* and *j*

Where: P^o is commodity prices pre-AEMI

P' is commodity prices post-AEMI

p_i^o is commodity *i* prices pre-AEMI

$p_i^{'}$ is commodity *i* prices post-AEMI

U^0 is level of utility (welfare) pre-AEMI

U' is level of utility (welfare) post-AEMI

M^0 is income pre-AEMI

$M^{'}$ is income post-AEMI

The Equivalent Variation (EV) can be defined as the dollar amount that the country would be indifferent to in accepting the changes in energy prices and income (wealth). It is the change in country wealth that would be equivalent to the prices and income change in term of its welfare impact (EV is positive if the prices and income changes would make the country better off). The Compensating Variation (CV) measures the net revenue of the planner who must compensate the country for the food prices and income changes, bringing the country back to its welfare (utility level) (Mas-Colell *et al.*, 1995). In this research, the database UN-COMTRADE is used to derive the coefficients of LES. The minimum energy or other products expenditure *i* is formulated as follows:

$$x_i^o = Min[x_{ij}] \text{ where } j \,\forall\, all\ data\ base \tag{12}$$

while the marginal budget share for energy or other products expenditure *i* is formulated as:

$$\alpha_i = \frac{x_i}{\Sigma x_i} \tag{13}$$

The welfare impacts of price equalisation in EMI impacts are divided into two: (i) direct impact (solely due to price equalisation in a specific energy price), and (ii) indirect impact (due to price changes of other goods as responses of price equalisation in a specific energy price). To measure the price changes of other goods with respect to price equalisation in a specific energy price, this research applies price elasticity, which is formulated as follows (Elasticity of change ΔP_j with respect to change ΔP_i):

$$\varepsilon_{ij} = \frac{\partial \ln P_j}{\partial \ln P_i} = f(\propto_i, \propto_j, \Delta P_i) = \frac{\propto_j}{\propto_i} \Delta P_i \quad (14)$$

The positive elasticity means the increase in a specific energy price leads to increase in the price of other non-energy products or other energy products. In contrast, the negative elasticity means the increase in a specific energy price leads to decrease in price of other non-energy products or other energy products. Chang, *et al.* (2013) simulated only the direct impact of AEMI, but in the research, both direct and indirect impacts of AEMI were considered.

Data

This paper uses data on import value and volume of energy products in 1979-2012 for ASEAN5 countries (Indonesia, Malaysia, Singapore, the Philippines, and Thailand) from the United Nations Commodity Trade Statistics Database (UN Comtrade), published by the United Nations (UN). This research uses the 3-digit SITC Revision 2. The imported products are classified into 10 groups, as follows:

- SITC 322: Coal, lignite and peat
- SITC 323: Briquettes; coke and semi-coke; lignite or peat; retort carbon
- SITC 333: Crude petroleum and oils obtained from bituminous minerals
- SITC 334: Petroleum products, refined
- SITC 335: Residual petroleum products, nes, and related materials
- SITC 341: Gas, natural and manufactured
- SITC 351: Electric current

- SITC 0-2
- SITC 4-8
- SITC 9

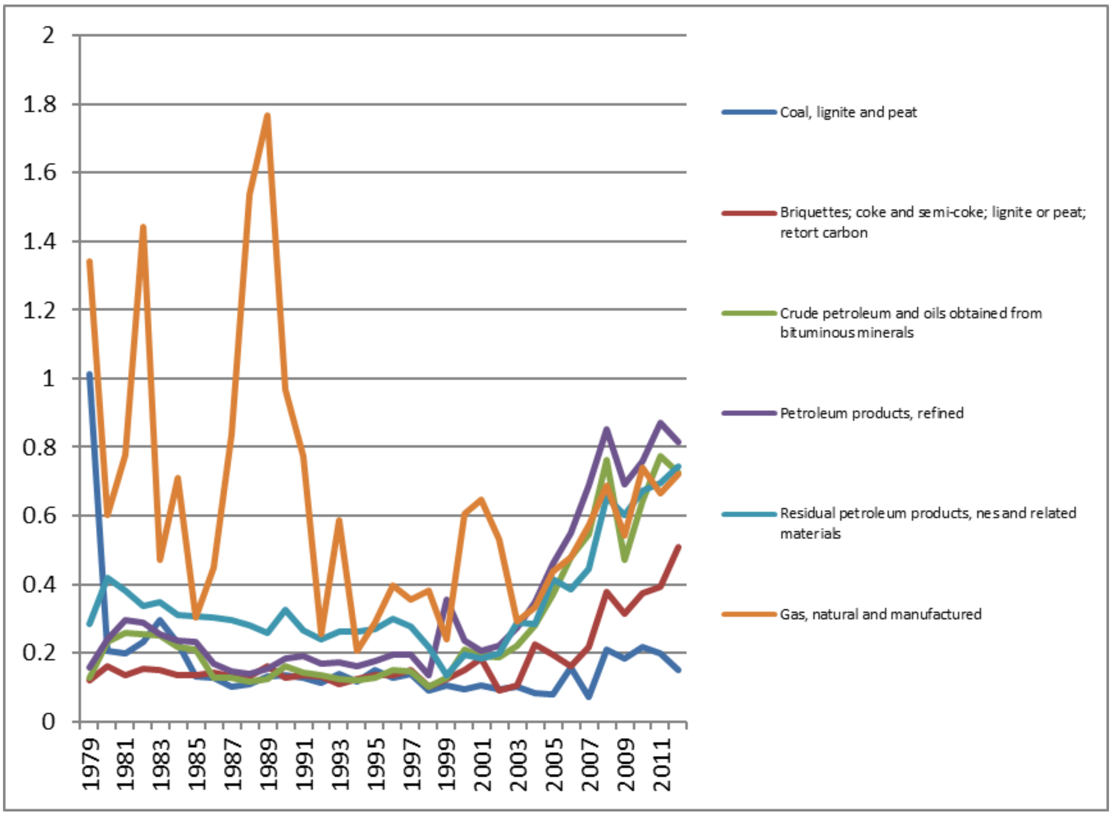
Results

Price Equalisation

Figure 5.1 shows the trend in average import prices of energy products in ASEAN5 for the period 1979-2012. Since the end of 2000s, there were positive trends in average import prices of energy products in ASEAN5. The subsidy policies for energy consumption are commonly implemented not only in developing countries but also in developed countries. There are many forms of energy subsidy, especially electricity subsidy policy, and fuel (kerosene, diesel, and LPG) subsidy policy (IEA *et al.*, 2010). In the Philippines, 94 percent of total subsidies are allocated to the energy subsidy while in Indonesia, it is 58 percent. Similar to Indonesia, Thailand and the Philippines also subsidise their energy sectors, especially oil and electricity. Both of them set the retail domestic oil price and electricity price paid by consumers. Those prices are lower than the world price. The governments of Thailand and the Philippines subsidise the difference between world price and their domestic price.

Figure 5.1. Trend in Average Import Prices of Energy Product in ASEAN5 for 1979-2012 (in US$/kg)

Positive trend in import energy prices



Source: UN Comtrade, and authors' calculation.

Since the domestic energy market in ASEAN countries are distorted, energy prices do not obviously reflect the efficient competitive market price. With subsidy, domestic energy prices have been set below the efficient market. Energy product prices vary among ASEAN countries. This paper uses variation coefficient (VC) to see the discrepancy of energy product prices. The smaller the VC, the less variation exists in energy product prices among ASEAN countries. In contrast, the higher the VC, the more variation exists in energy product prices among ASEAN countries.

Table 5.1: Estimation Results

Price equalisation in energy product occurs until a certain level of price variation is reached in the long-term

No (1)	SITC (2)	Commodity Description (3)	Constant β_1 (4)	Coefficient β_2 (5)	Conclusion (Hypothesis: β_1=0 and $\lvert\beta_2\rvert\geq 1$) (6)	Conclusion (7)
1	322	Coal, lignite and peat	0.57***	0.50***	Converge monotonically toward positive steady state of variation coefficient	Price equalisation occurs until a certain level of price variation is reached
2	323	Briquettes; coke and semi-coke; lignite or peat; retort carbon	0.23***	0.42**	Converge monotonically toward positive steady state of variation coefficient	Price equalisation occurs until a certain level of price variation is reached
3	333	Crude petroleum and oils obtained from bituminous minerals	0.07***	0.22	Converge monotonically toward positive steady state of variation coefficient	Price equalisation occurs until a certain level of price variation is reached
4	334	Petroleum products, refined	0.28***	-0.15	Converge oscillatory toward positive steady state of variation coefficient	Price equalisation occurs until a certain level of price variation is reached
5	335	Residual petroleum products, nes and related materials	0.24***	0.41**	Converge monotonically toward positive steady state of variation coefficient	Price equalisation occurs with certain level of price variation
6	341	Gas, natural and manufactured	0.50***	0.40**	Converge monotonically toward positive steady state of variation coefficient	Price equalisation occurs with certain level of price variation

Note: SITC = Standard International Trade Classification.
*, **, and *** denote significance at 10%, 5%, and 1% level of significance, respectively.
Source: UN Comtrade, and authors' calculation.

Table 5.1 shows the estimation results of the econometric AR model that is applied to examine the long-term (steady state) of VC and the process of price equalisation. Column (4) and Column (5) confirm that the constants (β_1) statistically differ from zero and the relative values of the coefficient (β_2) are less than 1. The variation coefficients converge monotonically and oscillatory toward positive steady state. This implies that the price equalisation process occurs until a certain level of price variation for all energy products is reached.

Simulation of Welfare Impact

The EMI in the ASEAN will potentially lead to an increase in the domestic energy product prices in the member countries as shown in the following arguments. *First*, the existing domestic energy product markets in ASEAN are distorted by subsidies and other government interventions. With the subsidies, domestic energy product prices are relatively low. Subsidies are defined as any government intervention that lowers the cost of energy production, raises the revenue of energy producers, or lowers the price paid by energy consumers. These are socially acceptable if these subsidies could advance social welfare and job creation, and encourage the development of new sources of energy that will enhance energy security. However, excessive energy subsidies in many countries, like Indonesia, have to compete for limited resources that could otherwise be used to deliver other essential services, widen the scope for rent seeking and commercial malpractice, discourage both supply-side and demand-side efficiency improvement, promote noneconomic consumption of energy, and can make new forms of renewable energy uncompetitive (IEA, OECD, OPEC, and The World Bank, 2010). Table 5.2 shows the presence of energy subsidy in some ASEAN countries. In the Philippines, 94 percent of total subsidies are allocated to the energy subsidy while in Indonesia, such allocation is 58 percent.

Table 5.2. Subsidies on Electricity, LPG, and Kerosene in Some ASEAN Countries

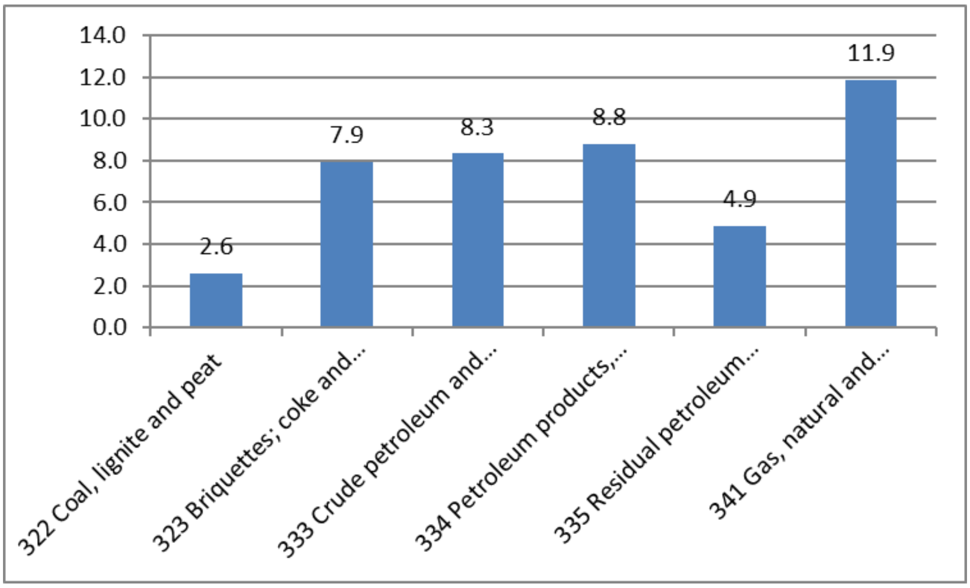
Goverments apply energy subsidies

Country	Presence of Subsidies			Electricity, LPG, & kerosene subsidies as a share in total subsidies (%)
	Electricity	LPG	Kerosene	
Indonesia	Yes	Yes	Yes	58
Philippines	No	Yes	No	94
Thailand	Yes	Yes	No	47
Viet Nam	Yes	No	No	39

Note: LPG = liquefied p

Sources: IEA (2010)

Figure 5.2. Average Annual Increase in Energy Product Prices for 1980-2012 (in %)



Source: UN Comtrade, and authors' calculation.

Second, the EMI would bring efficiency in resources allocation across the region, which in turn would lead to equalising the energy product market prices. Depending on the situation, it could lead to energy price increase in certain countries but decrease in the other countries. Most probably, all countries would experience increases in energy product prices differently. Figure 5.2 shows the average annual increase in energy product prices for 1980-2012. Gas recorded the highest annual increase, followed by petroleum and crude petroleum. Meanwhile, coal had the lowest annual increase.

Therefore, this research will use these figures to simulate the impact of price equalisation in EMI, i.e., energy price increases.

Table 5.3. Direct and Indirect Welfare Impact of Energy Product Increase in ASEAN5 (in US$/Year)

Measurement (1)	Coal, lignite and peat (2)	Briquettes; coke and semi-coke; lignite or peat; retort carbon (3)	Crude petroleum and oils obtained from bituminous minerals (4)	Petroleum products, refined (5)	Residual petroleum products, nes and related materials (6)	Gas, natural and manufactured (7)	Total increase in energy prices (8)
1. Direct Impact							
Compensating Variation	-55,933,359	-63,730,069	-11,182,685,413	-9,988,645,279	-117,183,840	-602,876,151	-22,068,387,330
Equivalent Variation	-55,930,664	-63,726,576	-11,121,207,424	-9,916,504,910	-117,172,649	-602,566,714	-21,773,051,304
2. Indirect Impact							
Compensating Variation	37,132,198,005	-10,059,582,396	-7,750,762,203	-6,357,719,212	-101,269,997,930	187,416,458,430	99,133,487,115
Equivalent Variation	38,123,844,357	-9,988,225,451	-7,522,478,059	-6,250,262,273	-94,531,521,626	215,654,843,725	103,098,426,091
3. Total Impact							
Compensating Variation	37,076,264,646	-10,123,312,465	-18,933,447,616	-16,346,364,491	-101,387,181,770	186,813,582,279	77,065,099,785
Equivalent Variation	38,067,913,693	-10,051,952,027	-18,643,685,482	-16,166,767,183	-94,648,694,276	215,052,277,011	81,325,374,787

Notes:

Column 2: Scenario increase in price of SITC 322—Coal, lignite and peat 2.6%
Column 3: Scenario increase in price of SITC 323—Briquettes; coke and semi-coke; lignite or peat; retort carbon 7.9%
Column 4: Scenario increase in price of SITC 333—Crude petroleum and oils obtained from bituminous minerals 8.3%
Column 5: Scenario increase in price of SITC 334—Petroleum products, refined 8.8%
Column 6: Scenario increase in price of SITC 335—Residual petroleum products, nes and related materials 4.9%
Column 7: Scenario increase in price of SITC 341—Gas, natural and manufactured 11.9%
Column 8: Scenario increase in all energy product simultaneously

Source: UN Comtrade, and authors' calculation.

Theoretically, the impacts are divided into two direct impacts (solely due to the decrease of certain energy price) and indirect impact (through the other price channels, using cross price elasticity). Table 5.3 shows that price equalisations (increases) in SITC 322 (Coal, lignite and peat) and SITC 341 (Gas, natural and manufactured) will bring positive welfare impact to the ASEAN5. In contrast, price equalisations (increases) in SITC 323 (Briquettes; coke and semi-coke; lignite or peat; retort carbon); SITC 333 (Crude petroleum and oils obtained from bituminous minerals); SITC 334 (Petroleum products, refined); and SITC 335 (Residual petroleum products, nes and related materials) will cause negative welfare impact. The simulation using the average annual increase of energy prices for 1980-2012, will bring positive total welfare (both direct and indirect) impacts of US$77,065,099,785 (CV) or US$81,325,374,787 (EV) per year. Although the price (increase) equalisation will certainly bring direct negative welfare impact, it also will give bigger indirect welfare impact. Energy products SITC 322, which are coal, lignite and peat; and SITC 341 comprising gas, natural and manufactured contribute to positive total welfare impact of price equalisation (increase) in ASEAN5.

Conclusions and Policy Implications

Theoretically, EMI would bring efficiency in resources allocation across the region, and eventually lead to equalising the energy product market prices. Depending on the situation, it could result in energy price increase in certain countries but price decrease in other countries. Most probably, countries will experience increases in energy product prices differently. This research finds that price equalisation process occurs until a certain level of price variation for all energy products is reached as variation coefficients converge monotonically and oscillatory toward a positive steady state. A coordinated and gradual subsidy reduction in energy is, therefore, more preferable to abrupt (big-bang) subsidy reduction. To bind the commitments of individual ASEAN member countries in reducing energy subsidy, the "Common Effective Preferential Energy Subsidy Reduction" (CEPESR) is required. This is like the Common Effective Preferential Tariff in ASEAN Free Trade Area (CEPT-AFTA). The CEPESR consists of the commitments of each individual member in reducing energy subsidy with preferred rate and period.

The simulation using the average annual increase of energy prices for 1980-2012 showed results that will bring positive total welfare (both direct and indirect) impacts of US$77,065,099,785 (CV) or US$81,325,374,787 (EV) per year. Although the price (increase) equalisation will certainly bring direct negative welfare impact, it will also result in bigger indirect welfare impact. Energy products SITC 322 (coal, lignite and peat) and SITC 341 (gas, natural and manufactured) will contribute to positive total welfare impact of price equalisation (increase) in ASEAN5. If among energy products to be integrated in ASEAN the first priority is given to SITC 322 (Coal, lignite and peat) and SITC 341 (Gas, natural and manufactured), which will contribute to potential positive welfare impacts to the ASEAN society, then the "ASEAN Coal and Gas Community" has to be considered in AEC. In fact, the EU, which is the predecessor of economic integration, established the European Coal and Steel Community (or the Treaty of Paris of 1951) before it created the European Economic Community (EEC) and the European Atomic Energy Community (Eurotom) (or the Treaty of Rome of 1957).

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CHAPTER 6

Market Integration and Energy Trade Efficiency: An Application of Malmqvist Index to Analyse Multi-Product Trade

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This paper uses the data envelope analysis method to investigate the Malmquist index-based gravity relationship between bilateral energy trade flows and their determinants throughout the world. Using a balance panel data of 40 countries between 1995 and 2008, this paper shows that market integration will increase energy trade by improving trade efficiency between trade partners, though allowing for a flexible substitution between different energy products tends to weaken these effects. This result highlights cross-product substitution and its implications for the aggregate energy trade pattern, providing insights on the importance of prioritising product-specific trade facilitating policies.

Keywords: energy trade efficiency, energy market integration, Malmquist index
JEL Classification: Q27, Q47, O47

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Introduction

Rapid economic growth in East Asia has substantially affected global energy consumption and its pattern over the past three decades. Between 1980 and 2012, the average gross domestic product (GDP) growth rate of countries in this region is more than 5 percent a year, which is more than double the GDP growth of Organisation for Economic Co-operation and Development (OECD) countries for the same period. The sustained economic growth, mainly due to the rapid expansion of manufacturing industries, led to two consequences. On one hand, it generated a huge increase in energy demand in the region and throughout the world. On the other hand, it created a significant disparity in energy supply and demand across regions. Since the late 1980s, energy consumption growth in this region has accounted for more than two-thirds of the world total, and the cumulative energy demand by this region is still increasing and likely to reach between 7 billion and 8 billion tonnes of oil equivalent (btoe) by 2030 (IEA, 2012).

Scholars and policy makers have reached the consensus that facilitating cross-country energy trade through forming a more integrated regional or global energy market can help stabilize market prices for energy products and secure energy supply (Shi and Kimura, 2010; Wu, *et al.*, 2014). This is because moving toward a more integrated energy market will increase the allocation efficiency of limited energy resources and resolve many economic and political issues related to the imbalance between energy supply and demand. However, limited progress has been made in practice, particularly from developing countries' perspectives. An important reason is that the aggregate benefits that all participants could obtain from involving themselves into regional and global market integration for energy products are hard to justify. In addition, there are also concerns about the fairness of benefit allocation across countries.

To quantify trade creation effects—an important benefit from forming market integration—trade economists have long been using the gravity model to examine the relationship between bilateral trade flow and its determinants (Anderson, 1979; Anderson and Wincoop, 2003; Costinot and Rodriguez-Clare, 2013). In literature, an essential argument is that market integration can increase trade efficiency and thus improve the welfare of all trade partners by providing additional trade creation. For example, Rose (2004) used a gravity model with a large panel data that covered over 50 years and 175 countries, and this showed that joining the Generalised System of Preferences (GSP) raised the bilateral trade by 136 percent, while Subramanian and Wei (2007) showed that membership to the General Agreement on Tariffs and Trade/World Trade Organization (GATT/WTO) significantly increased imports (around 44% of world trade) for industrial countries though unevenly across countries.Applying this method to analyse the impact of market integration on energy trade creation, many studies (Sheng and Shi, 2013) have also found a substantial positive trade creation effects through joining a more integrated energy market.

Although previous studies contribute to improve general knowledge, the accuracy of their predictions on the trade creation effects of market integration has always been criticized. In particular, the predicted trade creation or trade efficiency obtained from using the data at different aggregation levels are always inconsistent to each other (Subramanian and Wei, 2007). A possible explanation for this phenomenon, among others, is that the standard gravity model usually uses the aggregate trade value (i.e., summed up from commodities) as the dependent variable for the regression analysis. This treatment simplifies the exercise, but neglects the potential role of substitution/complementarity between various trade components in affecting the aggregate bilateral trade flow.

This paper uses the Malmquist index approach—a method initially designed for estimating the multi-output and multi-input production function—to investigate the gravity relationship between bilateral energy trade flows and their determinants. In contrast to previous studies, the approach used in this paper allows for a flexible substitution between different energy products in bilateral trade and thus provide a better measure of trade creation and trade efficiency due to energy market integration (EMI). Using a balance panel data for 40 countries between 1995 and 2008, this paper shows that regional integration will generally increase trade creation and trade efficiency though its effects on different products are different.

Compared to the conventional gravity model with perfect cross-product substitution, results in this paper suggest that the substitution between different energy products is likely to weaken the aggregate trade creation effects (or the trade efficiency gain) due to market integration. Moreover, the implicit shadow price of specific energy products relative to others (derived from the simulation) can change over time, implying that cross-product substitution and market integration process is interacted. A policy implication is that policy makers aiming to promote the bilateral energy trade flow need to prioritise the trade of the most valuable energy products.

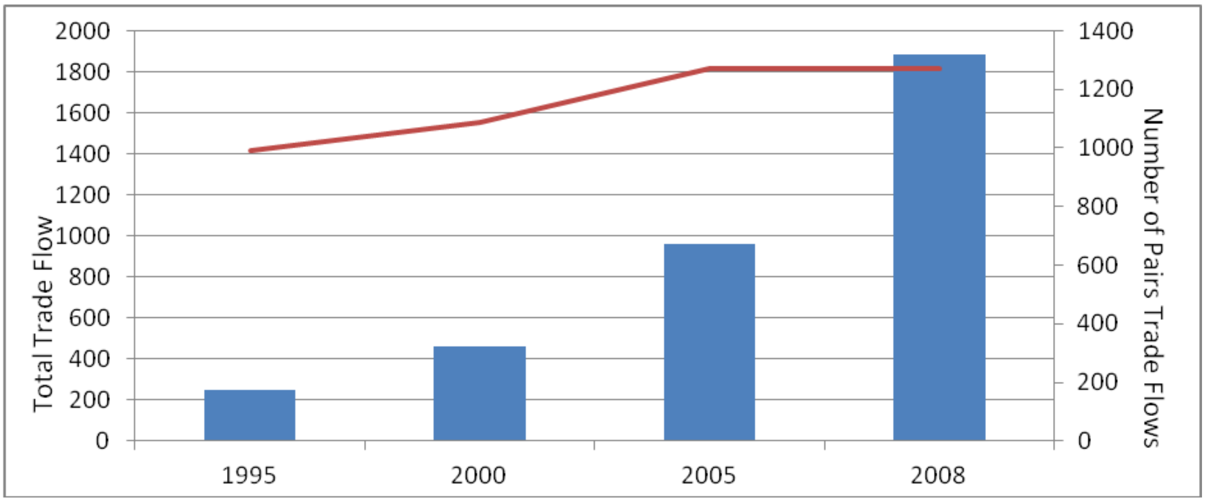
The remainder of the paper is organized as detailed below. Section 2 discusses the changing pattern of global energy trade and its components over the past two decades. A brief summary of the related literature follows. Section 3 provides the methodology and estimation strategy. The Malmquist index approach is employed to examine the gravity relationship between the bilateral energy trade flows and their determinants, and to provide the measure of trade efficiency when allowing for a flexible substitution between different energy products in trade. Section 4 describes the variables to be used and the related data sources, and provides descriptive statistics. Section 5 discusses the empirical results and Section 6 presents the conclusions.

Global Energy Trade and Cross-Product Substitution

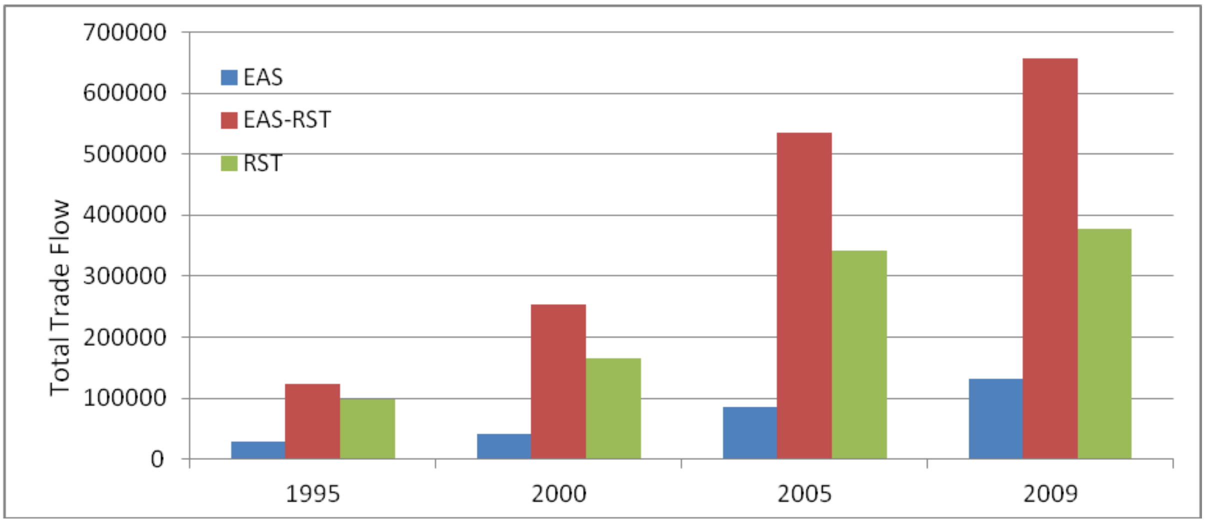
The energy trade has grown rapidly throughout the world over the past two decades, though its growth pattern is unevenly distributed across regions (Figure 6.1). Between 1995 and 2008, the total value of energy trade throughout the world has increased from US$249.5 million (at constant 2005 prices) to US$1885.4 million with an annual growth rate of 16.8 percent. The growth in energy trade associated with countries in the East Asia Summit (EAS) region is the most important driver. The total value of energy trade among the EAS countries and between the EAS countries and the rest of the world has increased from US$28 million and US$123 million, respectively, in 1980 to US$132 million and US$657 million in 2008. When added together, these account for around 70 percent of total world energy trade. Along with the strong growth in total energy flow, trade pattern has also become more diversified. The number of pairs trade has increased from 991 to 1,271 between 1995 and 2008.

Figure 6.1: Global energy trade and its components, by region, 1995–2008

A) Total trade flow and the number of pairs trade, 1995–2008 (in US$ billion at 2005 prices)



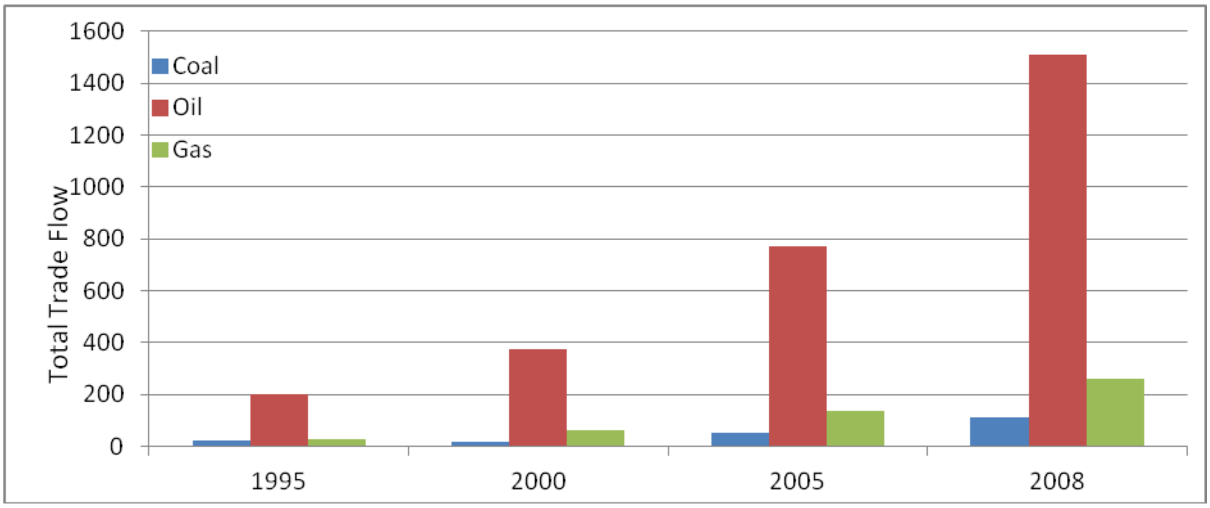
B) Cross-region distribution of energy trade, 1995-2008 (in US$ '000 at 2005 prices)



Source: Global Trade Analysis Project (GTAP) Energy Dataset.

However, the strong growth in total energy trade does not evenly apply to all energy products (Figure 6.2). Over the period 1995-2008, oil trade has been dominating the total energy trade. The average proportion of oil in total energy trade is around 80 percent, followed by natural gas (11%) and coal (9%). In terms of growth, the growth of trade in natural gas has taken the lead with an average annual growth rate of 19 percent, followed by oil trade (16.8%) and coal trade (13.5%). The uneven proportion (in total trade) and growth of trade in different energy products reflect their relative importance in the bilateral energy trade.

Figure 6.2: Components of global energy trade, by products, 1995-2008
(in US$ billion at 2005 prices)



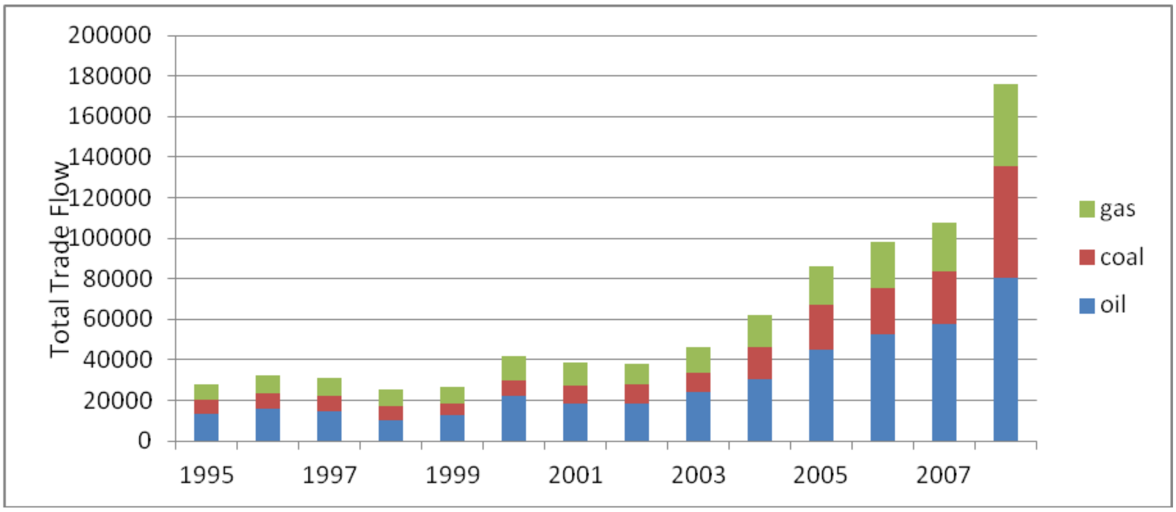
Source: Global Trade Analysis Project (GTAP) Energy Dataset.

The relative importance of different products also varies across different regions (Figure 6.3). For example, more than one-fourth of energy trade between countries within the EAS region is trade in coal and its share in total regional energy trade has increased from 26 percent in 1995 to 38 percent in 2008. In contrast, trade in coal only accounted for 7 percent of total energy trade between the EAS countries and the rest of world in 1995 and its share has further declined to less than 4 percent in 2008. The disparity in the relative importance of different products across regions is not only determined by the trading partners' characteristics in resource endowments, consumption preference, and production capacities but is also affected by the ease of different trade components' substitutability in consumption and its dynamic changes. Failing to consider this latter point may generate biased estimates on the aggregate trade flow.

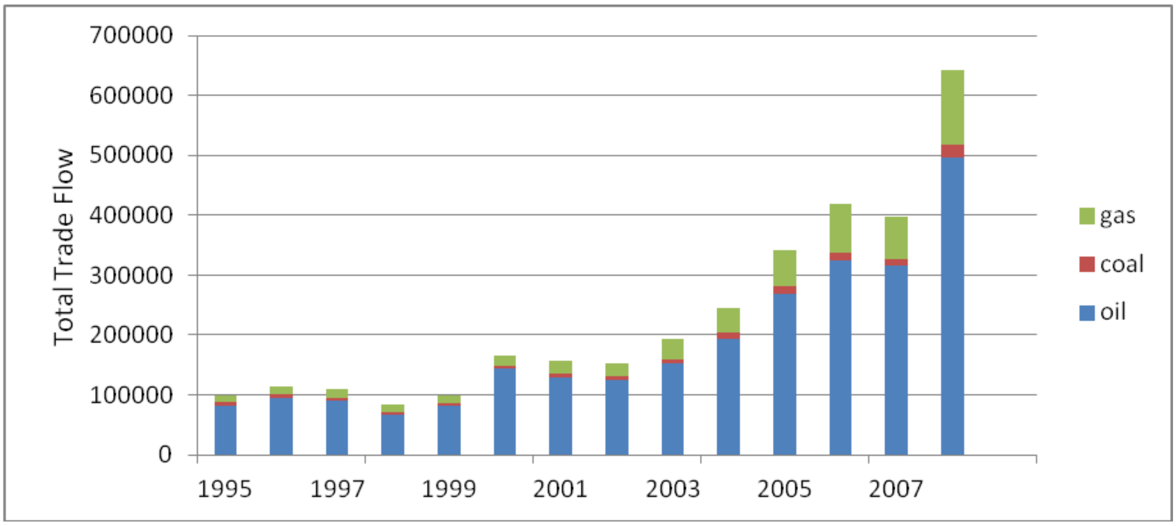
Figure 6.3: Cross-region comparison of energy trade components, 1995-2008

(in US$ million at 2005 prices)

A) Energy trade between the EAS countries, by products, 1995-2008



B) Energy trade between the EAS countries and the rest of the world, by products, 1995-2008



Source: Global Trade Analysis Project (GTAP) Energy Dataset.

Although there have been a large number of studies exploring the gravity relationship between bilateral energy trade and its determinants, only quite a few attempts have been made to combine the gravity model (for explaining the relationship between bilateral trade flow and its determinants) with the stochastic frontier analysis or the data envelope analysis(originally designed to measure efficiency in production or cost functions (Kuosmanen, *et al.* 2004) to quantify trade efficiency and its potential trade creation effects due to market integration. Trade efficiency is defined as the distance between actual trade flows and the maximum trade possible.

Following earlier studies in this field, several works (Drysdale and Garnaut, 1982; Kalirajan, 1999; Kalirajan and Findlay, 2005; Kang and Fratianni, 2006) applied the stochastic frontier analysis to the standard gravity model and investigated trade efficiency across 10 groups of countries throughout the world between 1975 and 2000 by using the bilateral trade data sets from Ross (2004). They showed that developed countries generally had higher trade efficiency than developing countries, and global and regional market integration contributed to raise cross-country trade efficiency. Among the Asia-Pacific region, the ASEAN has the highest trade efficiency while South Asian countries have the lowest efficiencies.

Kalirajan (1999) and Miankhel, *et al*. (2009) used the same method to examine the trade efficiency between Australia and its 65 trading partners during 2006–2008. They found that China and Japan, as well as ASEAN countries, are the key major trading partners that could provide substantial potential for Australia’s trade in mineral products (including energy products). Kalirajan and Singh (2008), following Drysdale, et al. (2000), examined the trade efficiency between China and its 56 trading partners and found that China’s efficiency was higher for trade with other Asia-Pacific region economies (especially, Chile, Hong Kong, Indonesia, Malaysia, Singapore, and Thailand) than with the European Union (EU) and the United States (US). Roperto (2013) and Roperto and Edgardo (2014) examined the trade efficiency between the Philippines and its trade partners and found that global and regional integration tend to increase trade efficiency among ASEAN countries.

The existing literature, though providing some useful information, suffers in general with two shortcomings. *First*, most of these studies focused on total trade with little implication for bilateral energy trade and the related market integration policies. *Second*, like conventional gravity studies, most of these researches use aggregate trade value as dependent variable to measure trade efficiency, which neglected the effects of cross-product non-substitution. In this paper, the Malmquist index is used to measure efficiency of multi-product energy trade when flexible substitution between trade components is considered.

The Malmqvist Index Approach and Trade Efficiency Measure

When investigating the gravity relationship between bilateral trade flow and its determinants, one can start by using a standard empirical specification, initially derived by Anderson (1979) and Anderson and Van Wincoop (2003), such that

$$lnX_{ij}^{k}(\tau,E) = A_i^k(\tau,E) + B_i^k(\tau,E) + \varepsilon^k ln\tau_{ij}^k + \mu_{it} \tag{1}$$

where

i — is the exporting country,

j— is the importing country, and

k— is the industry (or commodity/commodity group).

The terms $A_i^k(\tau,E)$ and $B_i^k(\tau,E)$ are income levels, which vary only at the ik and jk levels. τ_{ij}^k captures the 'partial equilibrium' effects of bilateral trade barrier or trade policies. μ_{it} is the residual that is used to capture the randomly distributed unobserved white noises. Equation (1) can be estimated by using different methodologies for specific purposes, including the identification of bilateral trade determination, the assessment of negative effects of regional integration, and so on.

In the literature for measuring trade efficiency, the stochastic frontier analysis or the data envelopment analysis are usually employed for the regression. Specifically, one can retrieve the best performing trade flow given trading partners' income level, trade barriers, and other controlled factors, and compare it with other trade flows to quantify their relative differences as a measure of trade efficiency. Normally, Equation (1) is specified to take the constant elasticity of substitution (CES) or the trans-log forms, and μ_{it} is assumed to contain an inefficient component (u_{it}<0) and a white noise (v_{it}), such that $\mu_{it} = u_{it} + v_{it}$. These methods work well for analysing trade flow (X_{ij}^{k}) at the commodity level, but it could not provide useful information on how trade flow may evolve and whether they are efficient at the aggregate level. This is because the substitution/complementary relationship between different components can usually change their aggregation and thus affect the measure of trade pattern at the aggregate level and its corresponding trade efficiency. In particular, when there are no perfect substitution between trade components, the model may tend to overestimate potential trade flow and trade efficiency.

To deal with the multi-outcome case, productivity economists designed the distance function method to retrieve the real substitutive/complementary relationship between different outputs (i.e., in production function), namely the Malmquist index. The method, initially used for estimating the production function, can now be used to investigate the gravity relationship between multi-product bilateral energy trade and its determinants. Since it assumes a relatively more flexible conversion function between different energy trade components, changes of trade in each energy product between any pair of trading partners can be identified through the calculation of the relative ratio of the distance of each data point relative to a commonly shared potential frontier.

With the standard assumption of imperfect substitution between multi-product energy trades ($y^{\cdot}$) and between trade determinants ($x^{\dagger}$.) , the Malmquist index between period t and $t+1$ is given by:

$$M_0 = [M_0^t * M_0^{t+1}]^{1/2} = [\frac{D_0^t(x^{t+1}, y^{t+1})}{D_0^t(x^t, y^t)} * \frac{D_0^{t+1}(x^{t+1}, y^{t+1})}{D_0^{t+1}(x^t, y^t)}]^{1/2} \quad (2)$$

This index is estimated as the geometric mean of two distance functions: one used as a reference the potential trade frontier at period *t* and the other used as a reference at period t+1 (Fare et al., 1994). Since the reference point can be defined as the potential maximum trade flow that could be achieved once the related trade determinants are constant, the Malmquist index can be treated as a measure of trade efficiency relative to the reference and its change over time could provide information on how the trade efficiency changed over time.

Moreover, Fare et al. (1994) also showed that the Malmquist index could be decomposed into an efficiency change component and a technical change component, and that these results could be applied to the different period-based Malmquist indexes.

$$M_{t,t+1} = \frac{D_0^{t+1}(x^{t+1},y^{t+1})}{D_0^{t}(x^{t},y^{t})} * \left[\frac{D_0^{t}(x^{t+1},y^{t+1})}{D_0^{t+1}(x^{t+1},y^{t+1})} * \frac{D_0^{t}(x^{t},y^{t})}{D_0^{t+1}(x^{t},y^{t})}\right]^{1/2} \quad (3)$$

The efficiency change component of the Malmquist indexes measures the change in how far the observed trade is from the maximum potential trade between period *t* and t+1, and the technical change component reflects the shift of natural created trade (due to demand and preferences) between the two periods. To define the trade determinants-based Malmquist index, it is necessary to characterise the trade determination mechanism (namely, the gravity model) and estimate its efficiency in trade generation.

Using Equations (2) and (3), the trade creation mechanism describes the possibilities for the transformation of trade determinants (x_t->R+) such as GDP, bilateral distances, and trade policies into energy trade flows (y_t->R+). Yet, the method looks like a black box and could not directly provide the relative importance of the different energy products as components in the total bilateral energy trade. To deal with this problem, this paper followed Coelli and Rao (2001) by using the simulation method and deriving the implicit share (or marginal contribution of various trade components and trade determinants) in the Malmquist index following the neoclassical assumption.

All efficient possibilities of bilateral energy trade in the time period *t* is characterised by the set (or the frontier of the set) of

$$D_0^t(x^t,y^t) = \max_{(x^t,y^t)\in L^t} \frac{\rho y^t}{\omega x^t} : \frac{\rho y^t}{\omega x^t} \leq 1 \quad (4)$$

The technology satisfies the usual set of axioms: closeness, non-emptiness, scarcity, and no free lunch. The frontier of the set for a given output vector is defined as the input vector that cannot be decreased by a uniform factor without leaving the set. Such a frontier can be estimated by using a minimisation process

$$\min_{\theta,\lambda} \theta_0 \qquad (5)$$

s.t.

$$\sum_{i=1}^{r} y_{ik}\lambda_i - y_{0k} \geq 0 \qquad k=1,\ldots,m$$

$$x_{0k}\theta - \sum_{i=1}^{r} x_{ij}\lambda_i \geq 0 \qquad j=1,\ldots,n$$

$$\lambda \geq 0$$

where

i— represents the *r* different TUs that defined the trade frontier,

k—are *m* trade flows, and

j—are *n* trade determinants.

The efficiency score obtained (θ) will take values between 0 and 1, with r indicating that the bilateral trade is located at the frontier.

Equation (5) is known as the data envelop form of the approach. An equivalent dual approach can be derived from its primal form (Kuosmanen, *et al.*, 2004). The envelope approach is preferred to the distance function way for estimating trade efficiency since it requires fewer constraints. Also, the current form has the advantage of a more intuitive specification, offering a better economic interpretation of the problem.

Using the above method, the impact of EMI policies on trade creation of multi-products can be estimated at the same time. In particular, the marginal contribution of each product to various determinants to trade can be isolated from the others through the dual method. This provides some useful knowledge to inform the relevant policies, since the marginal contribution of various trade determinants can be converted into corresponding cost-benefit ratios.

Data Collection and Variables Definition

Data used in this study come from four major sources including (i) the global trade analysis project (GTAP) energy product database, (ii) the UN Comtrade

Database and data used by Subramanian and Wei (Subramanian and Wei, 2007), (iii) the World Development Indicator Database, (iv) and the energy statistics from the BP Statistical Review of World Energy. Initially, the database cover the bilateral trade in three types of energy products, including coal, petrol, and gas across 172 countries (including 26 EAS countries) over the period 1995–2008. Yet, the real number of trade flows is much smaller than the initial dataset and many trade flows are zeros. This is because energy trade across countries heavily depends on exporting countries' initial natural endowments. Since the gravity model is more reliable in providing long-term projection, this paper uses the five-year average to smooth the year-to-year fluctuation in energy trade. Finally, the estimation of Malmquist index requires the balanced panel data, which impose the additional constraints.
With all three constraints considered, the sample size is cut down to 1,164 pairs of bilateral trade, covering 40 countries over four time periods—1995, 2000, 2005, and 2008. The sample is representative since they are added up to account for 44 percent of total energy trade of the whole world in 2008, which include 60 percent of coal trade, 43 percent of oil trade, and 45 percent of natural gas trade.

The dependent variable—the bilateral trade in coal, petrol, and gas between each pair of countries—is defined as real import value of each commodity. To make it comparable across countries and over time, nominal import values are deflated by using the corresponding commodity price at 2005 prices (provided by the GTAP datasets). It is to be noted that the import value rather than the total trade value was deliberately used to represent the bilateral trade since energy trade is usually a one-way trade. With such a treatment, the bilateral energy trade can be better captured by the characteristics of importers and exporters.

Independent variables first include the GDP per capita of both importers and exporters in US dollars at constant 2000 price and the geographical distances between the corresponding trade partners. Data for the period 1995–2000 are coming directly from Subramanian and Wei (2007) while data for the period after 2000 are coming from the World Development Indicator Database. Some adjustments have been made to make them consistent over time. In addition to the standard variables used in gravity models, the natural endowment of energy products in exporting countries are also used as control variables. This is important since it is impossible for countries holding no natural reserve in energy products to export. Data on natural endowment of natural reserves of each type of energy products in exporting and importing countries are obtained from various issues of the BP Statistical Review of World Energy.

Table 6.1 provides the summary statistics of the dependent variables (the bilateral trade in three energy products) and the major independent variables (i.e., GDP per capita, distance, and natural reserve in individual energy products).

Table 6.1: Logarithm of major variables in the regression

Variable Names	No. of Obs.	Mean	Std. Dev.	Min.	Max.
ln_agg._energy_trade	1164	5.16	2.18	0.00	11.46
ln_coal_trade	1164	1.81	2.19	0.00	9.83
ln_oil_trade	1164	3.67	3.17	0.00	11.06
ln_gas_trade	1164	0.81	2.07	0.00	10.33
ln_GDP_capita_importer	1164	8.73	1.49	5.43	10.64
ln_GDP_capita_exporter	1164	9.41	1.19	5.74	10.64
ln_distance	1164	7.73	0.97	5.09	9.34
ln_land_area	1164	26.84	2.59	17.81	32.20
dummy for common language	1164	0.17	0.37	0.00	1.00
dummy for FTA	1164	0.21	0.41	0.00	1.00
share of manufacturing industry	1164	29.01	11.40	4.00	94.40
ratio of energy to non-energy trade	1164	0.00	0.01	0.00	0.42
coal_ reserve_importer	1164	214.31	472.87	0.00	2802.00
oil_reserve_importer	1164	41.50	74.18	0.00	264.21
gas_reserve_importer	1164	3.29	5.32	0.00	29.61
coal_ reserve_exporter	1164	155.90	399.84	0.00	2802.00
oil_reserve_exporter	1164	8.97	28.48	0.00	181.50
gas_reserve_exporter	1164	0.97	2.13	0.00	29.61

Note: FTA = Free Trade Agreement, GDP = gross domestic product, No. of Obs. = Number of observations., Std. Dev. = standard deviation, max. = maximum, min. = minimum.
Source: Global Trade Analysis Project (GTAP) Energy Dataset.

Empirical Results: Multi-Product Energy Trade Determinants and Its Efficiency

Bilateral Trade Determination and Substitution between Trade Components

Applying the Malmquist index method to the data of bilateral energy trade, the gravity relationship is estimated between bilateral energy trade flows and their determinants, including the trading partners' economic growth, trade barriers (i.e., distance) and other controlled variables such as country-specific industrial trade and structure, Free Trade Agreement (FTA) participation, and initial endowment in natural resources. For robustness check, results obtained from two models are compared. The first model only uses the trading partners' GDP per capita and the geographical distance as the determinants of bilateral energy trade while the second model also incorporates other controlled variables. The results are shown in Table 6.2.

When allowing for more flexible substation/complementarities between different energy products, the marginal contribution of various trade determinants to bilateral trade flows are measured and reported in Table 6.2. These results are further compared with those obtained from the model, which uses the aggregate energy trade flow as the dependent variable.

Table 6.2: Marginal Contribution of Trade Determinants to the Aggregate Energy Trade

	Model I		Model II	
	Single-Product Energy Trade	Multi-Product Energy Trade	Single-Product Energy Trade	Multi-Product Energy Trade
ln_GDP_per_capita_importer	0.035***	0.009**	0.040***	0.011**
	(0.005)	(0.004)	(0.005)	(0.004)
ln_GDP_per_capita_exporter	0.025***	0.019***	0.037***	0.027***
	(0.006)	(0.005)	(0.006)	(0.005)
ln_distance	-0.007	-0.004	-0.038***	-0.018**
	(0.008)	(0.006)	(0.009)	(0.007)
Ratio of energy to non-energy trade	-	-	0.950*	0.964**
	-	-	(0.512)	(0.412)
Share of secondary industry in GDP	-	-	0.191***	0.724***
	-	-	(0.015)	(0.103)
Dummy_for_FTA	-	-	0.044**	0.017
	-	-	(0.022)	(0.017)
coal_reserve_cty1	-	-	-0.000***	-0.000***
	-	-	(0.000)	(0.000)
oil_reserve_cty1	-	-	0.001***	0.001***
	-	-	(0.000)	(0.000)
gas_reserve_cty1	-	-	0.008***	0.007***
	-	-	(0.002)	(0.001)
coal_reserve_cty2	-	-	0.000***	0.000***
	-	-	(0.000)	(0.000)
oil_reserve_cty2	-	-	0.001***	0.000*
	-	-	(0.000)	(0.000)
gas_reserve_cty2	-	-	0.006	0.000
	-	-	(0.004)	(0.003)
Constant	0.559***	0.443***	0.664***	0.496***
	(0.105)	(0.084)	(0.114)	(0.089)

Note: FTA = Free Trade Agreement, GDP = gross domestic product.
*** p<0.01, ** p<0.05, * p<0.1
Source: Global Trade Analysis Project (GTAP) Energy Dataset.

Consistent with the prediction of conventional gravity models, trading partners' economic growth positively contributed to bilateral energy trade while geographical distance negatively contributed to bilateral energy trade (Table 6.2). However, the magnitude of these coefficients of trade determinants is much smaller than that obtained from the traditional models (which assume that different energy products are perfectly substituted). This implies that using the aggregate energy trade flow as dependent variable may tend to overestimate the potential trade driven by conventional gravity drivers and thus cause the overestimation of trade efficiency, which is defined as the gap of real trade flow relative to potential trade flow.

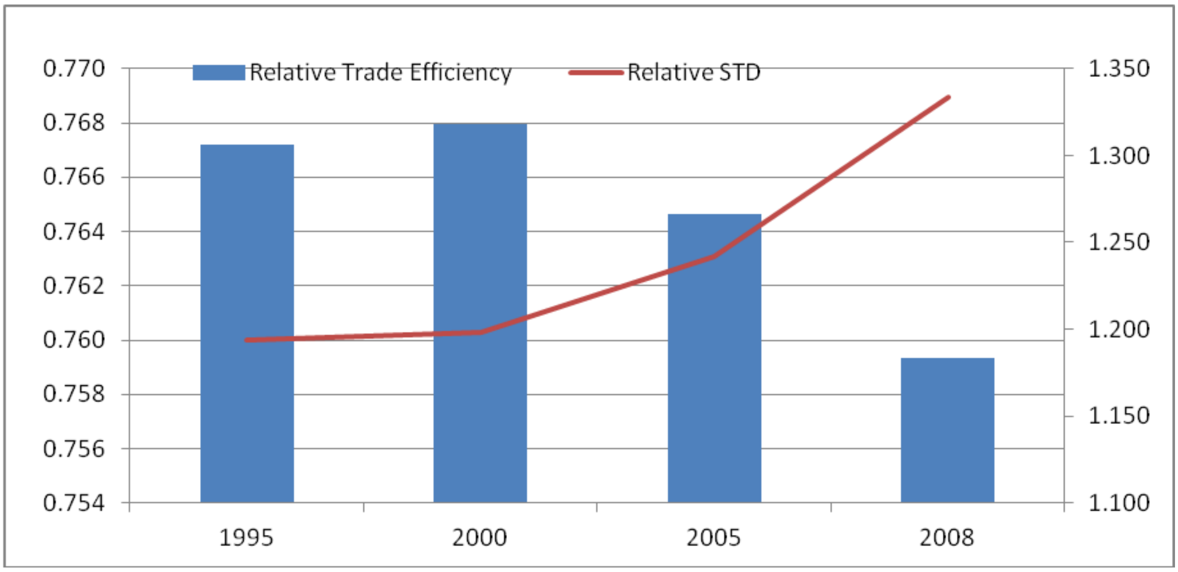
As an example, Table 6.3 compares the average growth in efficiency of bilateral energy trade between using the sum of energy trade (or the single-product trade model) and using the individual energy trade flow (or the multi-product trade model). Between 1995 and 2008, the average bilateral energy trade efficiency measured either by using the Malmquist index method for multi-product trade or by using the Malmquist index method for single-product trade has been increasing but their trends are different. In particular, the relative trade efficiency of the multi-product energy trade to that of the single-product energy trade declines while the standard deviation of estimated trade efficiency increases (Figure 6.4). This implies that bilateral trade efficiency, when flexible substitution between different energy products is allowed, is more likely to be diversified along with the increased mean.

Table 6.3: Comparison of Energy Trade Efficiency, 1995-2008

		Single-Product Trade		Multi-Product Trade	
Year	No. of Obs.	Mean	Std.	Mean	Std.
1995	291	0.344	0.153	0.264	0.183
2000	291	0.380	0.166	0.292	0.199
2005	291	0.417	0.172	0.319	0.214
2008	291	0.460	0.173	0.349	0.231

Note : No. of Obs. = Number of Observations, Std. = standard deviation.
Source: Authors' own estimation.

Figure 6.4: Relative Trade Efficiency by Different Assumptions–Mean and Standard Deviation



Note : Relative STD = relative standard deviation.
Source: Authors' own estimation.

In addition, the finding also shows that the exporters' initial endowment in energy resources (among other controlled factors) also affects the possibility of bilateral trade creation in energy products.

Efficiency of Energy Trade and Market Integration

Based on the assumption of a multi-product trade and the imperfect substitution between different energy products, empirical results show that the average efficiency in bilateral energy trade across countries has been improving over time. Between 1995 and 2010, there are on average more than 14 percent growth in cross-country energy trade for every five years with constant income growth and natural (i.e., geographical or endowment) trade barriers, though the trend tends to decline over time. This finding reflects the globalisation and regionalisation throughout the world and their potential impact on EMI and in promoting bilateral/multilateral energy trade.

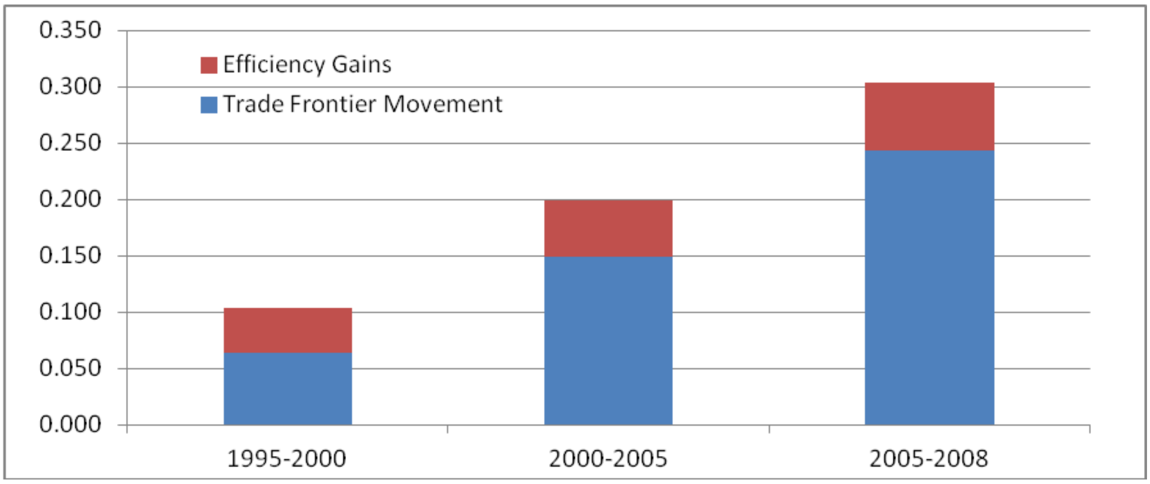
Table 6.4: Changes in Average Energy Trade Efficiency and its Components, 1995-2008

Year	Total trade	Frontier movement	Efficiency improvement
1995	1.000	1.000	1.000
2000	1.106	1.064	1.040
2005	1.207	1.149	1.050
2008	1.319	1.243	1.060

Source: Authors' own estimation.

A decomposition analysis shows that the rapid increase in the bilateral trade potential of energy products is driven by two forces: the contribution of advanced countries' efforts in further improving the trade efficiency, and the contribution of lagged countries' efforts in catching up with advanced countries. On average, the advanced countries' improving the trade efficiency accounted for around 70 percent of total efficiency gain in energy trade while lagged countries' catching up with advanced countries accounted for around 30 percent of total efficiency gain.

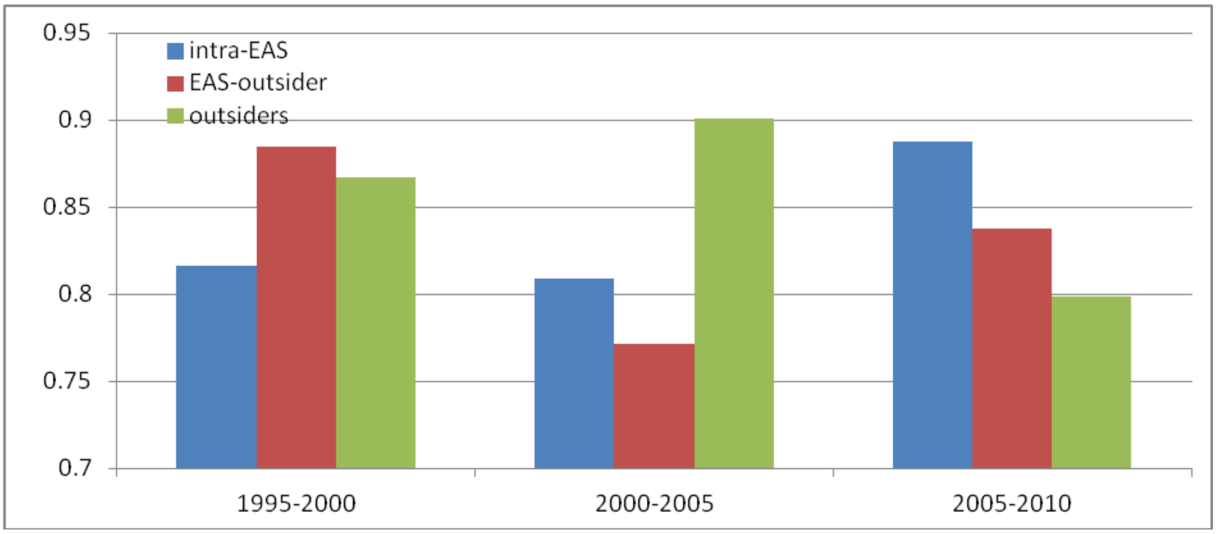
Figure 6.5: Trade Frontier Movement vs. Efficiency Gain, 1995-2008



Source: Authors' own estimation.

How does the trade efficiency of energy products change across different regions, in particular, within the EAS region? To answer this question, the bilateral trade flows were categorised into three groups: (i) the energy trade between EAS countries (intra-regional trade), (ii) the energy trade between EAS countries and the countries outside of the region, and (iii) the energy trade between countries outside of the region. The average efficiency of energy trade for each group of country pairs were estimated and presented in Figure 6.6.

Figure 6.6: Comparison of Average Energy Trade Efficiency, by Country Groups, 1995-2008



Source: Authors' own estimation.

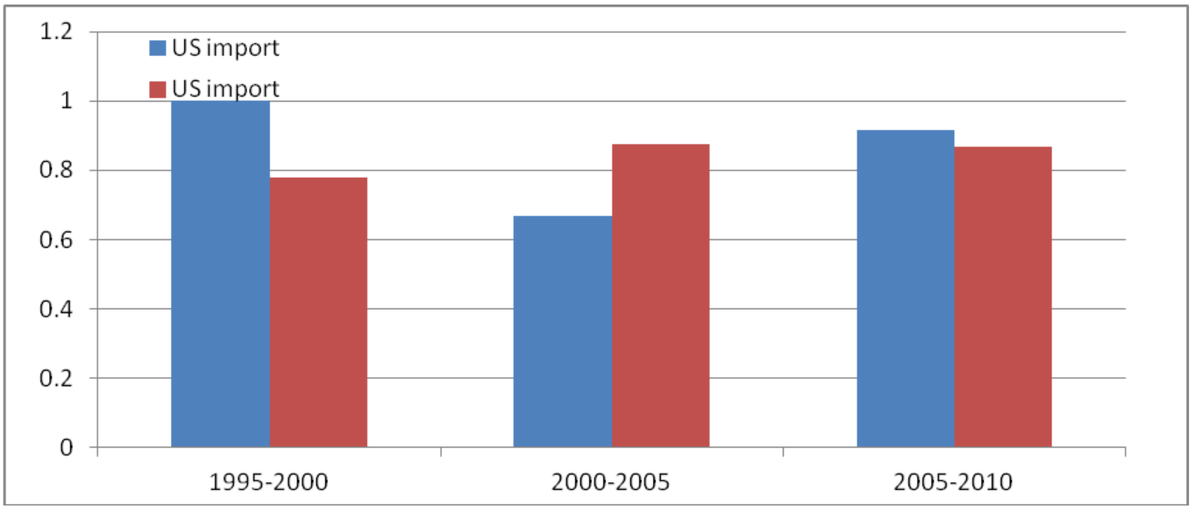
Comparing across the three groups of countries, the average energy trade efficiency between EAS countries has been low relative to that of countries in other groups, but it increased quickly over time. The average energy trade efficiency between EAS countries has increased from 0.82 in 1995 to 0.89 in 2008. Over the same period, energy trade efficiencies between EAS countries and countries outside of the regions and that between countries outside of the region have declined from 0.88 and 0.87 down to 0.86 and 0.84, respectively. This implies that public policies aimed at improving EMI, among other factors, have played an active role in facilitating cross-country energy trade.

Although the average energy trade efficiency between EAS countries has been increasing, there are still significant differences across countries. Figure

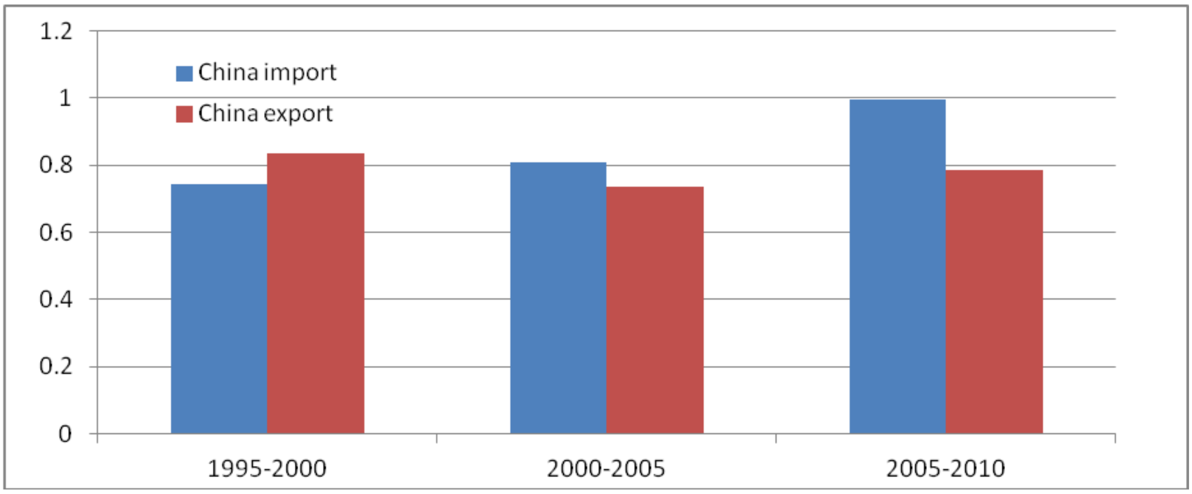
6.7 shows the average energy trade efficiency of three countries (the US, China, and Indonesia) in exports and imports. Over the period 1995–2008, energy trade efficiency of imports and exports between the US and its trading partners in the EAS region has been declining while that between China and its trading partners in the region has been increasing. This, in general, represents the changes in energy trade pattern between developed and developing countries due to their different performance in economic development and the related energy demand. As for Indonesia, energy trade efficiency of imports has been declining while that of exports has been increasing between 1995 and 2010. This finding is more likely to reflect the country's specific endowment in energy resources and its booming petrol and gas production.

Figure 6.7: Average Energy Trade Efficiency of Imports and Exports: United States, China, and Indonesia

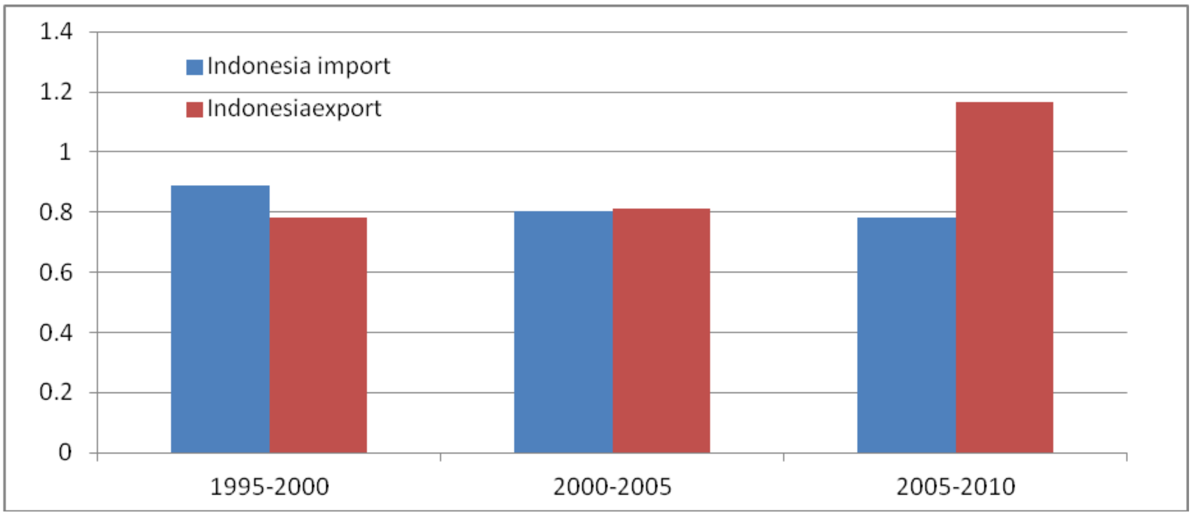
A) Average energy trade efficiency in the United States



B) Average energy trade efficiency in China



C) Average energy trade efficiency in Indonesia



Source: Authors' own estimation

Implicit Share: Importance of Trade Components in Bilateral Energy Trade

Using the Malmquist index to examine the gravity relationship between multi-product trade and its determinants, one can obtain additional results on the implicit prices for different trade components through the related simulation. Usually, these implicit prices may reflect the relative importance of each energy products in the aggregate energy trade. Based on Coelli and Rao (2001), the simulation is used to derive the implicit prices of all three energy products specified in the model—coal, petrol, and gas—and the results are shown in Table 6.5.

Table 6.5: Implicit Price of Coal, Petrol and Gas in Bilateral Trade Model

Year	ln_coal	ln_petrol	ln_gas
1995	0.414	0.237	0.000
2000	0.318	0.313	0.003
2005	0.203	0.371	0.008
2008	0.185	0.386	0.013

Source: Authors' own estimation.

Between 1995 and 2008, implicit prices of petrol and gas have been increasing faster relative to the price of coal. The implicit prices of petrol and gas increased from 0.24 and 0.00 in 1995 to 0.39 and 0.01 in 2008 while that of coal declined from 0.41 in 1995 to 0.19 in 2008. This result partly reflects the increasing importance of trade in petrol and gas in total energy trade possibly due to changing preference. An important implication is to further improve the aggregate energy trade efficiency across countries, with more emphasis given to petrol and gas since their performance continues to increase over time.

Policy Implication, Expected Result, and Future Development Study

The development level of East Asia is vastly different from that of Cambodia, Lao PDR, Myanmar, and Viet Nam (also called CLMV countries). The 2008 gross national income (GNI) per capita in current value is US$630 for Cambodia, US$750 for Lao PDR, and US$910 for Viet Nam, while that in developed EAS countries, Australia has a GNI per capita of US$41,890, Japan has US$37,930, South Korea has US$21,570, and New Zealand has US$26,830, all in current values. The difference between the richest and the poorest countries is more than 60 times. Since narrowing development gaps is a prerequisite for the process of regional integration, it is therefore very important to study the impact of EMI on growth convergence.

It is widely believed that EMI will help participants to be more closely related through improving the bilateral trade efficiencies. Yet, how the trade creation process is achieved is not yet well understood. To address this issue, this study provides policy makers with some useful information on what kind of impact EMI can have on potential energy trade and the dynamic path of energy trade in different products, particularly on its impact on country-specific products. As the analysis is narrowing the focus from the aggregate energy trade down to products, it improves the possibility of applying EMI-oriented policies for the region and in trade-related countries.

A few policy implications are expected. At the regional level, the productivity analysis will make it possible for stakeholders to understand the trade potential. This will help the regional policy makers to gauge their efforts. The estimated benefits will also reassure policy makers in their determination to move EMI forward. At the national level, *first*, information on the impact of EMI on product trade will help policy makers assess whether the consequence of EMI is acceptable since different kinds of energy products may have different strategic roles in each national economy. *Second*, this knowledge will make it possible for national policy makers to understand the impact by sector and, thus, they are able to formulate appropriate policies that will offset or enhance a particular impact.

Conclusions

This paper employs the Malmquist index approach to estimate the gravity relationship between bilateral energy trade and its determinants. Using a balance panel data of 40 countries covering the period between 1995 and 2010, a measure of energy trade efficiency at the aggregate level is provided and its change over time when considering the flexible substitution between different energy products, including coal, oil, and natural gas. Results show that along with the rapid growth in total energy trade, the trade efficiency in all energy products across countries have been increasing over the past two decades, particularly within the EAS region (though there are some cross-country disparities). Both the advanced countries' trade efficiency improvement and the lagged countries' catch-up efforts played important roles in driving such a change.

Results also show that different energy products contribute differently to the aggregate energy trade creation and to the corresponding trade efficiency gain. Generally, trade in coal accounts for the highest implicit prices but it has been declining over time relative to trade in petrol and gas, which suggests that trade in coal is losing its advantage over trade in petrol and gas. Thus, public policies that aim to improve regional EMI could benefit more by focusing on trade in petrol and gas.

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CHAPTER 7

Infrastructure Investments for Power Trade and Transmission in ASEAN+2: Costs, Benefits, Long-Term Contracts, and Prioritised Development

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This study establishes a system approach in assessing the financial viability of power infrastructure investment for the Greater Mekong Subregion (GMS) and ASEAN Power Grid (APG) in the ASEAN+2 (ASEAN plus China and India) region. It aims to identify the financial and finance-related institutional barriers of implementing such regional power interconnectivity. A whole-grid/system simulation model is built to assess both their financial and commercial viability, which implies profitability for investors and bankability for financiers of new transmission projects with the optimised pattern of power trade. The study also determines the optimised planning of new transmission capacities. Results show that the existing planning of power transmission infrastructure in the region, so-called APG+, stands as a commercially and financially viable plan. However, there is room for improvement in the planning in terms of timing, routes, and capacity of the cross-border transmission lines. The study also recommends that GMS-related projects should be prioritised.

Keywords: cross-border power trade, power infrastructure, financial viability, commercial viability

JEL: Q40, Q41, Q48

Introduction

The Greater Mekong Subregion (GMS) program lead by the Asian Development Bank (ADB) and the ASEAN Power Grid (APG) program lead by the Association of Southeast Asian Nations (ASEAN) have made steady progress, mainly driven by bilateral power trade that comes with long-term power purchase agreements (PPAs). According to ADB definitions, this progress constitutes the stage 1 developments of regional power interconnections. Three more stages of developments are to be witnessed before an integrated GMS or ASEAN power market comes into being (ADB, 2013; Zhai, 2010).

The four stages of developments are

- Stage 1, bilateral trade with PPAs;
- Stage 2, grid-to-grid power trading between any pairs of member countries, even using the transmission lines through a third member country;
- Stage 3, development of transmission lines dedicated to free power trading instead of specific PPAs; and
- Stage 4, fully competitive regional market with multiple sellers and buyers from each member country.

Table 7.A1 and 7.A2 in Appendix A show the existing power transmission lines for cross-border interconnections, and the ongoing and planned transmission line projects within ASEAN and extended to the neighbouring parts of Southwest China[1] and Northeast India[2] (ASEAN+2). Table 7.A2 covers the APG program and additional programs initiated by governments in the region, which will be referred to as "APG+" henceforth.

It is evident that a significant amount of investment in the interconnection capacities should be done. According to the ASEAN Plan of Action for Energy Cooperation (APAEC), 2010-2015 (ASEAN Centre for Energy,

[1] Yunnan and Guangxi provinces.
[2] Northeastern states.

2007), the total investment of APG, which includes 15 projects, amounts to US$5.9 billion.[3] While governments and intergovernmental organisations, such as ADB and the World Bank, could lead the early stage of developing the interconnected and integrated power markets, the next stages of intensive investment in the infrastructure would inevitably need to engage the private sector.[4] Therefore, new investment in cross-border transmission lines should stand commercially and financially viable—profitable for investors and bankable for financiers—to attract investments from the private sector. The following concerns are identified as the key issues.

First, investment in transmission lines is a capital-intensive business, usually costing from millions to billions in US dollars. Table 7.1 shows the capital expenditure (CAPEX) of some typical projects undertaken in the ASEAN countries, using data from ADB. The average cost of a transmission line in megawatt per kilometre (MW/km) terms decreases as the length and capacity of the line increases.

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[3] According to APAEC 2010-2015, a potential savings of about US$662 million dollars in new investment and operating costs of the grid/system is estimated to result from the proposed APG interconnection projects.

[4] For example, the ASEAN Infrastructure Fund (AIF) has a total lending commitment through 2020 that is expected to be around US$4 billion. If the 70% cofinancing to be leveraged from ADB is added, the total amount of public finance available will be US$13 billion, which covers not only the energy sector, but also investments in infrastructure for clean water, sanitation, and better forms of transportation. http://www.adb.org/features/fast-facts-asean-infrastructure-fund

Table 7.1: CAPEX of Power Transmission Lines in the ASEAN Context

Case	Voltage	Line Length (km)	Capacity	CAPEX (US$)	$/MWh*
1	500 kV	200	500	167,200,000	9.1
2	500 kV	400	500	297,900,000	16.1
3	500 kV	200	1000	242,000,000	6.6
4	500 kV	200	1000	152,400,000	4.1
5	500 kV	400	1000	449,500,000	12.2
6	500 kV	200	2000	312,100,000	4.2
7	500 kV	200	2000	292,200,000	4.0
8	500 kV	400	2000	732,500,000	9.9
9	500 kV	400	2000	630,800,000	8.5

Note: CAPEX = capital expenditure, km = kilometre, kV = kilovolt, MWh = megawatt-hour.

* *Embedded assumptions include: 40 years of asset life, 10% discount rate, load factor at 5,000 hours per year, operation costs as 2% of the CAPEX, and transmission loss at 2%.*

Source: Hedgehock and Gallet (2010).

Second, cross-border power trade further complicates the business with political, social, and environmental considerations. It is for these reasons that the projects are considered high risks and require long-term contracts to reduce the risks and secure the stream of revenue. These include long-term public-private partnership (PPP) contracts such as build-own-operate-transfer (BOOT) and build-operate-transfer (BOT), and long-term power service contracts such as power purchasing agreements (PPAs) or concession-based contract with guaranteed payment for the new line. The costs, especially financial costs of transmitting power across borders, then critically depend on these factors (Barreiro, 2011; World Bank, 2012; Neuhoff, *et al*., 2012).

Third, the profitability of each transmission line will depend on the evolution of the pattern of cross-border power trade in the region. This is because the demand and supply landscape may change quickly in some countries in the region, and new transmission lines dilute the power demand from existing transmission lines (Hogan, 1999; Joskow and Tirole, 2003; Kristiansen and Rosellon, 2010). Thus, understanding future power trade patterns and regionally integrated planning are critical to investment decisions in transmission lines.

These concerns—high CAPEX, investment risks, and uncertainty about future regional power trade pattern—raise the key question of commercial and financial viability of the proposed new cross-border transmission capacities in the region. On the one hand, literature on the benefits of regional power market interconnection in ASEAN generally reflects positive results, particularly from the Asia Pacific Energy Research Centre (2004), ASEAN Centre for Energy (2007), and Chang and Li (2013a). Chang and Li (2013b) also show that APG enables further policy options in the region to achieve sustainable development, namely to promote renewable energy and carbon emissions reduction, in the power sector. However, in view of the progress of interconnection in the real world, few literatures extend the discussion into financial viability of new transmission infrastructure investment in this region. This study will fill this gap with a comprehensive perspective in optimally planning the power infrastructure development.

In this study, a financial sub-model for investments in power transmission infrastructure is to be developed and integrated into a dynamic linear programming model developed by Chang and Li (2013a and 2013b). The sub-model will specifically address the financial viability of power transmission infrastructure for regional power trade and power market interconnectivity among the ASEAN+2 countries.

The model produces the optimised pattern of both bilateral power trade in the early stage, and multilateral trade in a fully competitive and integrated regional power market by considering the costs of generating electricity and transmitting power across borders. The optimised trade pattern, thus, shows the most likely development of power trade in the region. Based on this outlook on power trade, the model indicates where new power transmission capacities are needed most, resulting in high utilisation rate of the new capacities and, therefore, making the investment financially viable.

The results could also be used to suggest an investment priority in new power transmission lines by envisioning the needs of the future power trade pattern. This future power trade pattern depends on the different energy resource endowment of countries in the region, the growth of domestic power demand, and the evolving power generation technologies and fuel costs. Thus, power trade is envisioned as dynamically changing, and this determines the financial viability of new cross-border transmission capacities. These facts are duly reflected in the model.

Lastly, it is worth noting that this model takes the perspective of a regional transmission grid planner and optimises investments in infrastructure to ensure commercial and financial viability of these investments. Such a methodology echoes the call for a single international/regional planning body to effectively implement cross-border grid expansion through accurate market modeling and projection. The European cross-border power market is an example of this kind (Frontier Economics, 2008).

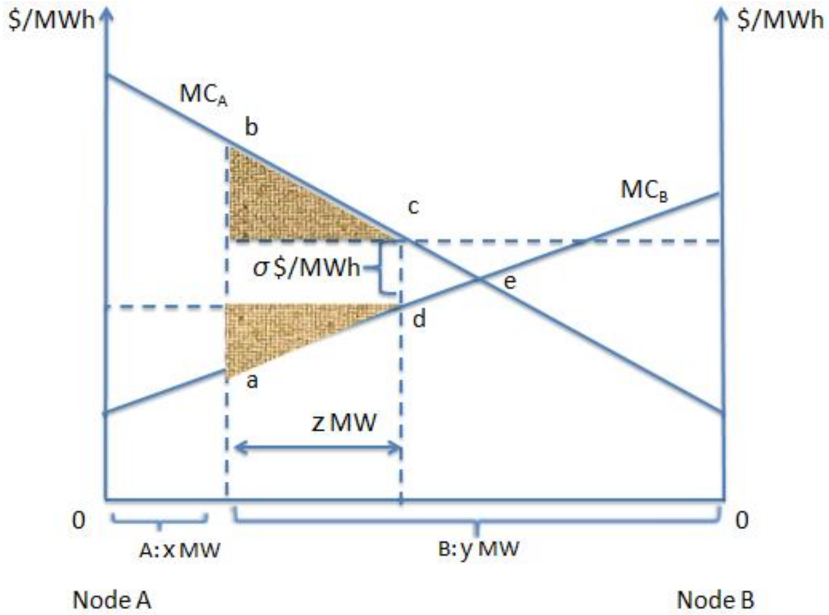
In this paper, specific research questions and what methodology would be applied to address the questions are discussed in section 2. Section 3 expounds what data would be required for this study and how to acquire such data. Section 4 presents and analyses results from the model. Finally, section 5 concludes with policy implications based on these results.

Methodology and Scenarios

Assessment of Financial Viability of New Transmission Lines

It is a well-known theory that the value of transmission line should be determined by the cost of congestion in the grid and the idea of congestion charge is developed accordingly, which is the commercial value as well as the source of revenue of a transmission line in a competitive electricity market (Joskow and Tirole, 2003; Kirschen, 2011). Figure 7.1 shows how the optimal transmission capacity should be determined in a simplified case, which in this case is a two-node electricity market.

Figure 7.1: Commercial Value of Transmission Line and Optimal Capacity



Source: authors

The horizontal axis shows the power demand at nodes *A* and *B*, respectively, in megawatts (MW), while the vertical axis shows the marginal cost of power generation in dollar per megawatt-hour ($/MWh). Clearly, nodes *A* and *B* have different levels of power demand, and different marginal cost curve of power generation. At node *A*, the power demand is *x* MW, while at node *B*, the power demand is *y* MW. This results in different marginal costs of power at the two nodes, at levels corresponding to where points *a* and *b* are for nodes *A* and *B*, respectively.

If there is a transmission line to connect nodes *A* and *B*, node *A* could produce more than *x*MW and supply node *B* at a lower marginal cost of power. If the transmission is free of cost, node *A* should supply as much as when its marginal cost of power is equal to that of node *B* at point e. This is known as the no congestion case. However, if transmission is costly, optimal capacity of transmission is where the savings in the marginal cost (the difference between marginal cost of generation from node *B* and that from node *A*) is equal to the marginal cost of transmission capacity. Assuming that the marginal cost of transmission capacity is σ $/MWh, as shown in the figure, the optimal capacity of transmission capacity is determined at *z* MW.

In this optimal case, σ \$/MWh is equal to the congestion cost to the system and, therefore, the commercial value of the transmission line. In a competitive market, σ \$/MWh should be charged accordingly for using the transmission line. The actual utilisation rate of the transmission line, which means how many MWh of electricity is transmitted, determines whether the investment in the transmission line could expect a reasonable return. Usually, this is where long-term PPP contracts come in to ensure the financial viability of the investment.

It is noted that such an investment in the transmission capacity generates a positive net savings to the system, which consist of nodes A and B. The savings is represented by the two shaded triangle area in Figure 7.1. Such net savings is the key to proving the commercial viability of the new transmission line; otherwise, the line has no commercial value added and should not be built.

In a grid with multiple nodes, the estimation of congestion cost is complicated, and it becomes necessary to take a whole-grid/system approach (Lesieutre and Eto, 2003). Network externality effect of new transmission lines further complicates the issue. Therefore, in this study, a whole-grid/system approach is taken in assessing both the financial and commercial viability of new transmission projects with optimised pattern of power trade; the approach is also suitable for optimising the planning of new transmission capacities.

First, the model integrates a 30-year contract for new transmission capacities, which ensures that revenues collected over this period will meet the commercial investors' internal rate of return (IRR) requirement. *Second*, with costs of new transmission lines modeled as such, the system generates cost minimisation planning for all power infrastructures—namely, power plants and cross-border transmission lines—so as to meet the growing demand for electricity in the region during the modeling period. *Lastly*, the minimised total system cost is to be compared with the benchmark case in which no new cross-border transmission line is built. Should the former be smaller than the latter, it means that there is net system savings resulting from the optimised planning for new cross-border transmission lines.

In this case, recalling the simplified grid case in Figure 7.1, the power trade with an optimised planning of new transmission lines not only ensures the investors' IRR to be achieved but also delivers net system savings, which means that such a transmission investment plan stands as both financially and commercially viable. [5] Should the net system savings be negative, it implies that the financial viability of the new projects with long-term contracts could not hold or be self-sustaining. This methodology is a major innovation and, thus, is a contribution to the literature. It enables the comprehensive assessment of financial viability of cross-border transmission investment plans from a system perspective.

The mathematical model could be found in Appendix B. Specifically, the cost of new transmission lines under the long-term contract is specified in Equation 3 in Appendix B. The objective value in Equation 4 represents the total cost of the system.

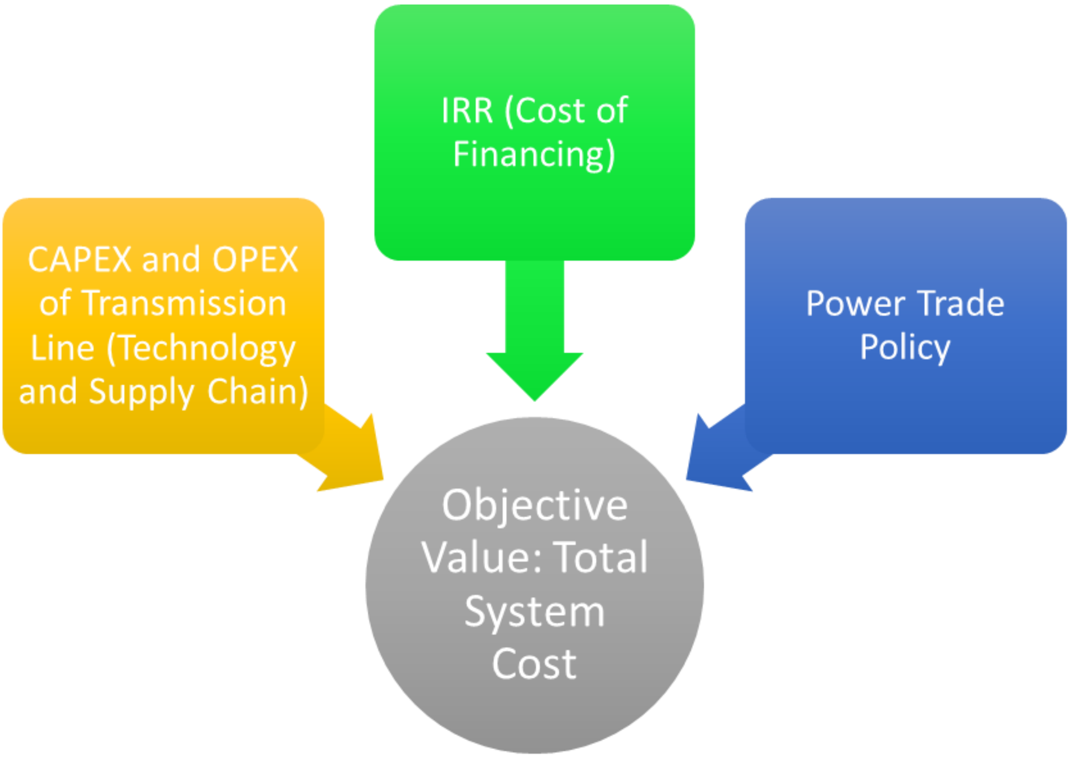
Modeling Policy Options and Financial Viability of Transmission Lines

Various policies are identified as key factors to financial viability (Figure 7.2). *First,* CAPEX and operation expenditure (OPEX) directly drive up the cost of transmission lines. Policies toward the introduction and absorption of new technologies could help reduce the cost. Policies that help reduce lead-time of the new transmission project, such as facilitating project preparation, supply chain coordination, construction, and grid connection can also significantly reduce the cost of new transmission lines. *Second*, financial costs of transmission line investments are very sensitive to the IRR of investors, which in turn is sensitive to all project-related risks including market risks, technical risks, institutional risks, and political risks. Policies that relieve these risks could help reduce the cost of transmission lines significantly. *Third*, power trade policies of countries in the region—namely ASEAN + China (Yunnan and Guangxi) and India (Northeastern provinces)—determine the demand for the import and export of power and, therefore, the commercial value of new transmission lines. In this study, such policies are modeled as

[5] In other words, the new transmission lines have net commercial value, and financial viability is not achieved at the expense of the total system but, in fact, by saving the total system costs.

the percentage of domestic power demand to be met through power trading with other countries.

Figure 7.2: Key Factors for the Financial Viability of Cross-Border Transmission Lines



Source: authors.

In this study, scenarios are built mainly to assess the impact of policies that facilitate power trade in the region, as the demand for power trade and future trade pattern are the most fundamental forces in determining where new transmission lines are needed and when they are needed.

This study aims to conduct two experiments. The first one aims to identify what would be the optimal plan of new transmission capacity development, which is not only financially viable but also maximises net savings for the system. The second aims to assess the financial viability of the APG+ plan as it is currently announced. The optimised development plan will then be compared to the existing APG+ plan to derive some policy implications. Table 7.2 summarises the scenarios.

Table 7.2: Scenarios for Simulation of Interconnected Regional Power Market

Scenario	Description
Benchmark	No new transmission line will be developed
Opt-20	Optimised transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
Opt-50	Optimised transmission development with countries allowing up to 50% of domestic power demand to be met by trade with other countries
Opt-80	Optimised transmission development with countries allowing up to 80% of domestic power demand to be met by trade with other countries
APG-20	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
APG-50	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
APG-80	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries

Source: authors

Data Inputs

Data about the CAPEX (capital expenditure) and OPEX (operation expenditure) and their relations to key drivers, such as length and capacity of the transmission line, will be the key inputs into the proposed new model. In this study, CAPEX of the transmission line is assumed to be US$1,086/MW per km and OPEX is assumed to be 2% of the CAPEX, following the data reported by Hedgehock and Gallet (2010). IRR is assumed to be 10% with a

30-year contract period for investors to own and operate the transmission capacity. The modeling period is 2012–2050, considering the long life span of power infrastructure assets.

Other data inputs required for the model, such as demand for power, energy resources, cost of power generation capacities and so on, have been discussed in detail in Chang and Li (2013a and 2013b). The dataset is updated and extended according to the scope of this study, mainly for the inclusion of China and India into this study.

Results and Analysis

New Transmission Lines and Net Savings of Total System Cost

As shown in Table 7.2, the simulation focuses on the cross-border power trade policy of the ASEAN+2 region, which fundamentally determines the commercial value of new transmission lines for cross-border power interconnectivity. Table 7.3 provides a summary on how the total power system cost in each scenario with new transmission capacity is compared with that of the benchmark scenario, which assumes no new capacity added. With positive net savings in the total system cost achieved, financial viability of the new infrastructure development is implied.

Table 7.3: Comparison of Total System Costs in Different Scenarios and the Net Savings*

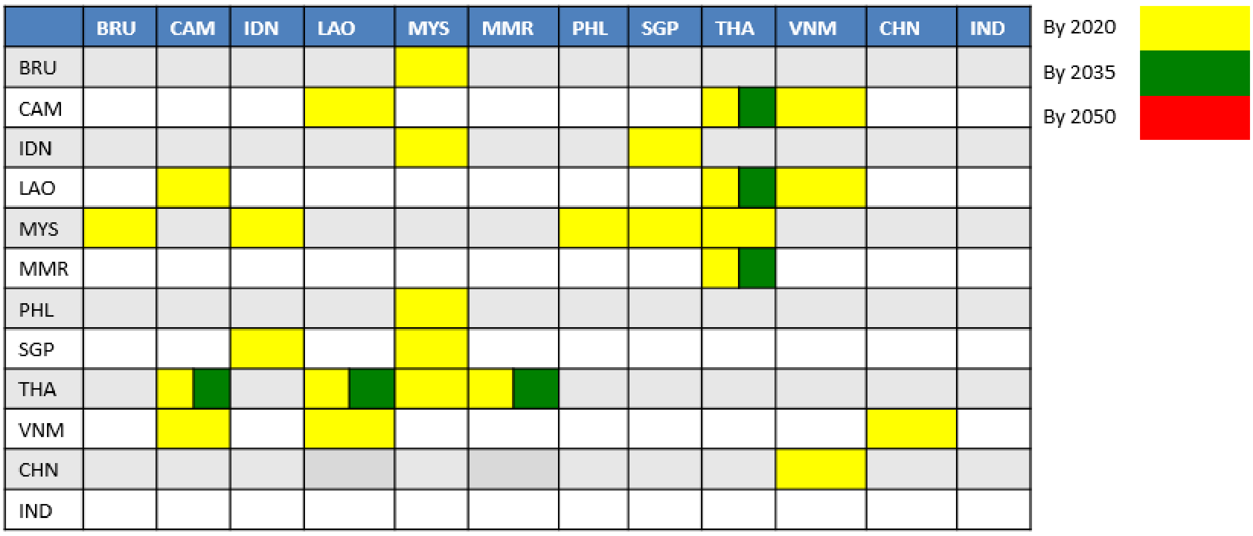
Scenario	Total System Cost (US$ trillion)	Benchmark Scenario Total System Cost (US$ trillion)	Net Savings (US$ billion)	Percentage of Savings
Opt-20	1.240	1.242	2.0	0.16
Opt-50	1.187	1.195	8.0	0.67
Opt-80	1.165	1.176	11.0	1.00
APG-20	1.241	1.242	1.0	0.10
APG-50	1.192	1.195	3.0	0.25
APG-80	1.172	1.176	4.0	0.34

Note: * Numbers are rounded.
Source: authors.

From the table, it is observed that the current APG+ stands as a financially and commercially viable program, since the net total system savings are positive from APG-20 to APG-80. However, the net savings from APG+ are much smaller compared to the scenarios from Opt-20 to Opt-80 in which transmission development is optimised. Such implies that there is room for improvements in the existing APG+ plan in terms of routes, timing, and scale of projects.

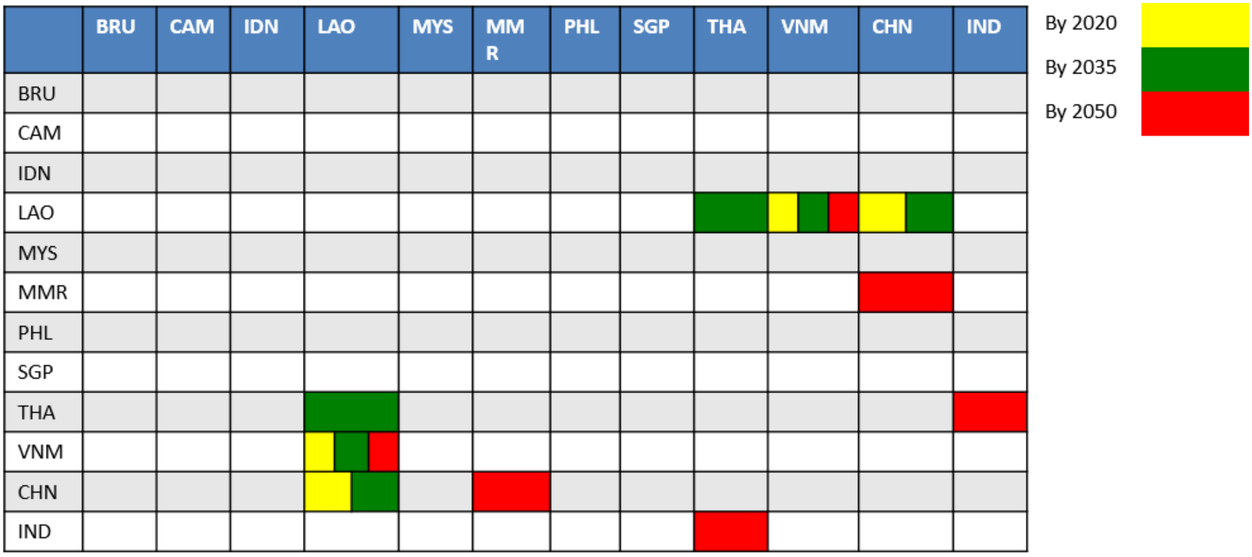
Figures 7.3 to 7.6 provide a visual description of the difference between optimised transmission development plans and the APG+ plan.

Figure 7.3: The Existing APG+ Plan



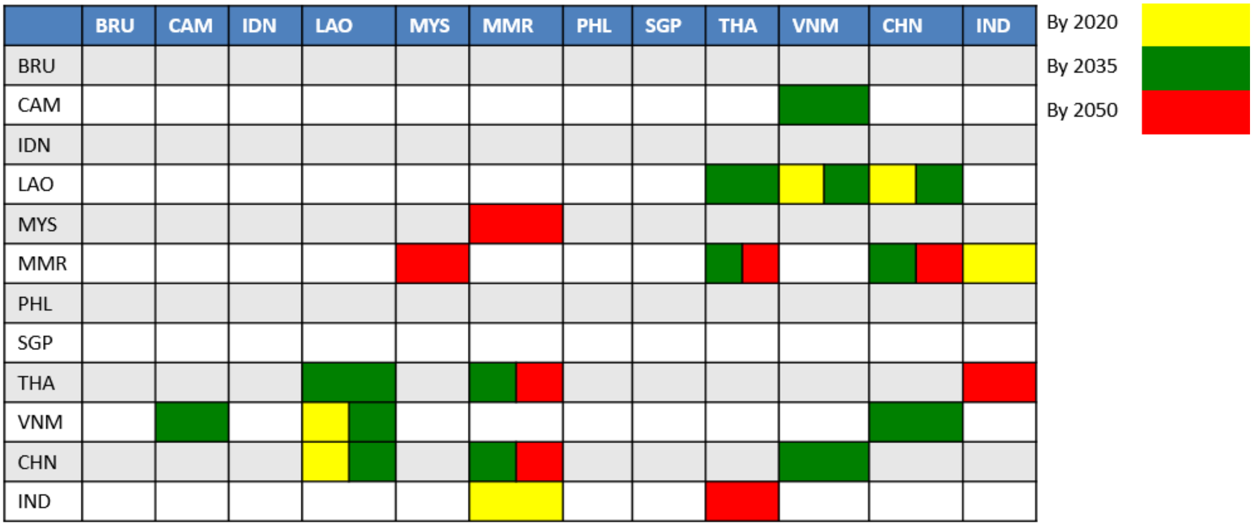
Source: authors

Figure 7.4: Optimal Transmission Development under Opt-20



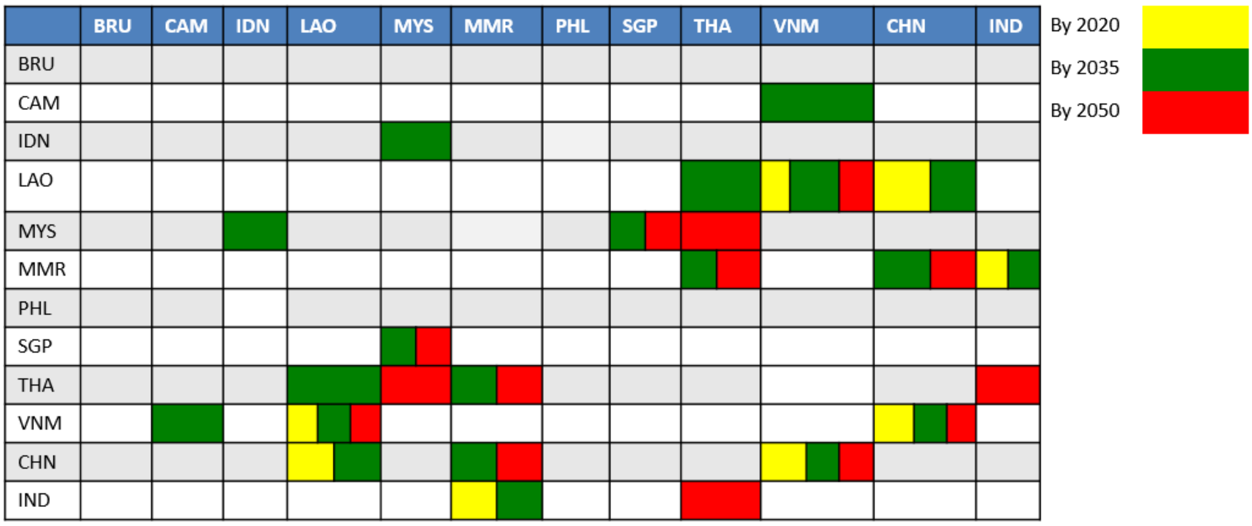
Source: authors.

Figure 7.5: Optimal Transmission Development under Opt-50



Source: authors.

Figure 7.6: Optimal Transmission Development under Opt-80



Source: authors

Comparing Figure 7.3 with Figures 7.4, 7.5 and 7.6, it is observed that

(1) optimal transmission development only agrees with APG+ on the priority of interconnectivity between the Lao People's Democratic Republic (Lao PDR), Viet Nam, and China;

(2) optimal transmission development suggests that interconnectivity between Lao PDR, China, Myanmar, and India be prioritised and should materialise before 2020;

(3) many other projects proposed in APG+ should be put in the second priority and be developed before 2035 rather than 2020. Examples of such projects include the interconnectivity among Cambodia, Viet Nam, Lao PDR, Myanmar, and Thailand; and

(4) all simulations show that new transmission developments in the GMS subregion is at the centre of future regional cross-border power trade.

The findings are also in line with those from ERIA (2014), which takes the case study approach and agrees that some of the APG projects need to reconsider their priority in development to ensure financial viability.

Optimal Power Trade Pattern in the Region

Results in the previous subsection are derived based on how power generation capacities will be optimally developed based on resources available, cost of the capacity, cost of transmission, and on how cross-border power trade will be optimally carried out based on the amount of power needed, the time it is needed, and where it is needed. Therefore, it is necessary to check if the simulation results of these two variables are reasonable and realistic.

Figure 7.7: Pattern of Power Trade in the Opt-20 vs. Apt-20

Source: authors.

Since allowing 20% of domestic power demand to be met by cross-border trade is the most realistic policy case, Figure 7.7 focuses on scenarios with such a policy assumption. A single arrow indicates one-way power trade, while double arrows mean two-way power trade. Red colour represents the trade routes optimised in the Opt-20 scenario, while yellow colour represents trade routes added in addition to the red ones in the APG-20 scenario. The dashed red arrow represents a trade route that existed in the Opt-20 scenario but not in the APG-20 scenario. In addition, there are two more trade routes in the APG-20 not shown in this map and they are the Malaysia to Brunei one-way trade, and the Malaysia to the Philippines two-way trade.

In the Opt-50 scenario, which allows for up to 50% of domestic power demand to be met by trade with other countries, all routes in the APG-20 are adopted, except for those to Brunei and the Philippines. In addition, a two-way trade between India and Myanmar will be added.

The practice on the comparison of future trade pattern has two implications: (1) Most of the cross-border power trade will happen in the GMS region, with possible extension to Northeast India; and (2) APG+ brings more opportunities of power trade in the ASEAN+2 region. However, if trade policy is not bold enough as to, for example, allow up to 50% of demand met by trade, then it is unclear whether these trade brings more total system cost savings as the cost of investment on APG+ is also very high.

In Opt-50 (see Figure 7.5), the scale of investment on ASEAN+2 interconnectivity is similar to APG+ with most of the routes of transmission lines the same. However, Opt-50 brings more total system cost savings (0.67%) than APG-20 (0.10%) or APG-50 (0.25%).

Conclusions and Policy Implications

This study aims to develop a financial sub-model of cross-border power transmission lines in the ASEAN+2 region and integrate it into the ASEAN cross-border power trade model developed by Chang and Li (2013a and 2013b). The results of this new model, thus, draw the implications on the financial viability of cross-border transmission infrastructure to be developed in the future based on a comprehensive vision of future power trade patterns that considers the interacted effects from all existing and proposed transmission line projects. For example, the completion of a new transmission line may change the current trade pattern that is built on existing infrastructure. It is the new trade pattern after the completion of this new line that will determine the utilisation of the new asset and therefore the financial viability of it. Such a comprehensive market-modelling approach for the estimation of financial viability is better than looking at the cost and benefit of a new transmission line project alone with assumptions that are fixed and isolated from the dynamic development of trade pattern in the region.

The following key observations are made based on the results of the model.

1. Existing APG+ stands as a commercially and financially viable plan if long-term PPP contracts, which allow as long as 30 years of payback

time with 5% of discount rate and 10% of IRR for investors, are applied.

2. Projects in the GMS area should be given priority, as they are most desired in future cross-border power trade in the region. These projects also stand financially viable under certain conditions, while policies should be designed to encourage and facilitate the entry of private sector investment.
3. This model further indicates that by optimising the routes and timing of the power interconnectivity in the region, the total system costs could be further reduced and, therefore, the commercial and financial viability of the connectivity projects could be further strengthened.
4. Policies on cross-border power trade are critical to the financial viability of investment in new transmission capacities. Other policies that affect the CAPEX and OPEX of the investment, and the risks associated with the investment, are also important and their impacts on financial viability could also be assessed using this model.
5. It is noted that this simulation model is only an assessment of theoretical financial viability, which assumes the projects are all delivered on time without meeting barriers in cross-border regulation, legislation, or standards harmonisation. In this sense, to ensure that theoretical financial viability becomes reality, policies should be designed and implemented to relieve non-financial barriers so as to keep investment risks low and enable the financial viability.

The following types of policy implications could thus be derived based on the above observations.

1. Power interconnectivity in the ASEAN+2 region stands as commercially and financially viable, given that supportive policies, such as long-term PPP contracts for infrastructure investment, more freedom for cross-border power trade, harmonisation of regulation and standards to reduce risks associated with these infrastructure, and lead time of project development, are in place.
2. Systemic and detailed modelling of the power interconnectivity in the ASEAN+2 region is needed to optimise the planning of infrastructure investment and to accurately assess the financial viability of these investment projects.

3. Despite the theoretical feasibility of ASEAN+2 power interconnectivity indicated by this study, many economic and political issues should be further studied. As Neuhoff, *et al*. (2012) correctly pointed out in studying the financing of European Union's power interconnectivity, in reality, the question of how to share the costs and benefits of the transmission infrastructure with an international mechanism between two or three countries involved should also be paid attention to since these are cross-border transmission lines and there will be mismatched incentives for different parties.

Despite the meaningful findings, it is noted that this study has its limitations. Future studies are needed as the region needs more detailed models for both long-term power infrastructure investment planning and system operation modeling, as in the case of the European Union (EU) and the regional markets in the United States (US). For EU, examples are REMIND (Leimbach, *et al*., 2010), WITCH (Bosetti, *et al*., 2006), MESSAGE-MACRO (Messner and Schrattenholzer, 2000), and POLES (Russ and Criqui, 2007) on a global scale, and PRIMES (Capros, *et al*., 2010) on the European level. For the US, examples on a European scale are ELMOD (Leuthold, *et al*., 2008), representing the European transmission infrastructure with great detail, and ReMIX (SRU, 2010), which calculates hourly dispatch and transmission flows for one complete year.

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Appendix A: Existing Power Transmission Lines for Cross-Border Interconnections

Table 7.A1: Existing Cross-Border Power Transmission Lines

Country A	Country B	Project Name	Capacity (MW)
Malaysia	Singapore	Plentong - Woodlands	450
Thailand	Malaysia	Sadao - Chuping	80
Thailand	Malaysia	Khlong Ngae - Gurun	300
Lao PDR	Thailand	Theun Hinboun - Thakhek - Nakhon Phanom	220
Lao PDR	Thailand	Houay Ho - Ubon Ratchathani 2	150
Lao PDR	Thailand	Nam Theun 2 - Roi Et 2	1,000
Lao PDR	Thailand	Nam Ngum 2 - Na Bong -Udon Thani 3	615
Lao PDR	Thailand	Theun Hinboun (Expansion) - Thakhek - Nakhon Phanom 2	220
Lao PDR	Viet Nam	Xehaman 3 - Thanhmy	248
Viet Nam	Cambodia	Chau Doc - Takeo - Phnom Penh	200
Viet Nam	Cambodia	Tai Ninh - Kampong Cham	200
Thailand	Cambodia	Aranyaprathet - Banteay Meanchey - Siem Reap - Battambang	120
China	Viet Nam	Xinqiao - Lai Cai	250-300
China	Viet Nam	Maguan - Ha Giang	200
Myanmar	China	Shweli 1 - Dehong	600

Source: Chimklai (2013); Zhai (2010); ADB (2013); APERC (2004); Bunthoeun (2012).

Table 7.A2: Ongoing and Planned Cross-Border Power Transmission Line Projects (APG+)

Country A	Country B	Project Name	Capacity (MW)
Thailand	P. Malaysia	Su - ngai Kolok - Rantau Panjang	100
Thailand	P. Malaysia	Khlong Ngae - Gurun (Addition)	300
Malaysia	Sumatra (Indonesia)	Melaka - Pekan Baru (AIM II Priority Project)	600
Sarawak (Malaysia)	W. Kalimantan (Indonesia)	Mambong - Kalimanyan	230
Sabah (Malaysia)	E. Kalimantan (Indonesia)	Newly Proposed	200
Sarawak-Sabah (Malaysia)	Brunei	Sarawak - Brunei	200
Lao PDR	Thailand	Hong Sa - Nan 2 - Mae Moh 3	1,473
Lao PDR	Thailand	Nam Ngiep 1 - Na Bong - Udon Thani 3	269
Lao PDR	Thailand	Xe Pien Xe Namnoi - Pakse - Ubon Ratchathani 3	390
Lao PDR	Thailand	Xayaburi - Loei 2 - Khon Kaen 4	1,220
Lao PDR	Thailand	Nam Theun 1- Na Bong - Udon Thani 3	510
Lao PDR	Thailand	Nam Kong 1 & Don Sahong - Pakse - Ubon Ratchathani 3	315
Lao PDR	Thailand	Xekong 4-5 - Pakse - Ubon Ratchathani 3	630
Lao PDR	Thailand	Nam Ou - Tha Wang Pha - Nan 2	1,040
Lao PDR	Viet Nam	Ban Hat San - Pleiku	1,000
Lao PDR	Viet Nam	Nam Mo - Ban Ve - (Vinh)	100
Lao PDR	Viet Nam	Sekamas 3 - Vuong - Da Nang	250
Lao PDR	Viet Nam	Xehaman 1 - Thanhmy	488
Lao PDR	Viet Nam	Luang Prabang - Nho Quan	1,410
Lao PDR	Viet Nam	Ban Sok - Steung Treng (Cambodia) - Tay Ninh	Unknown
Lao PDR	Viet Nam	Ban Sok - Pleiku	1,151
Lao PDR	Cambodia	Ban Hat - Stung Treng	300
P.Malaysia	Singapore		600
Batam (Indonesia)	Singapore	Batam - Singapore	600
Sumatra (Indonesia)	Singapore	Sumatra - Singapore	600
Philippines	Sabah (Malaysia)		500
Sarawak - Sabah (Malaysia)	Brunei	Sarawak - Sabah - Brunei	100
Thailand	Lao PDR	Nong Khai - Khok saat; Nakhon Phanom - Thakhek; Thoeng - Bokeo;	600
Thailand	Cambodia	Prachin Buri 2- Battambang	300

Thailand	Cambodia	Trat 2 - Stung Meteuk (Mnum)	100
Thailand	Cambodia	Pluak Daeng - Chantaburi 2 - Koh Kong	1,800
Myanmar	Thailand	Mai Khot - Mae Chan - Chiang Rai	369
Myanmar	Thailand	Hutgyi - Phitsanulok 3	1,190
Myanmar	Thailand	Ta Sang - Mae Moh 3	7,000
Myanmar	Thailand	Mong Ton - Sai Noi 2	3,150
China	Viet Nam	Malutang - Soc Son	460
China	Thailand	Jinghong - Lao PDR - Bangkok	1,500
Myanmar	India	Tamanthi - India	960
Cambodia	Viet Nam	Sambor CPEC - Tan Dinh	465

Source: Chimklai (2013); Zhai (2010); ADB (2013); APERC (2004); Bunthoeun (2012).

Appendix B: A Dynamic Linear Programming Model for Cross-Border Power Trade

CAPEX

The following models the capital expenditure (CAPEX) of a certain type of power generation capacity at a certain point of time. Let x_{miv} be the capacity of plant type *m*, vintage *v*,[6] in country *i*.[7] And c_{miv} is the corresponding capital cost per unit of capacity of the power plant. So the total capital cost during the period of this study would be $\sum_{i=1}^{I}\sum_{v=1}^{T}\sum_{m=1}^{M} c_{miv} * x_{miv}$. (In GAMS code, for consistency in presentation with the other cost terms, a time dimension is added to the equation besides the vintage dimension. By doing that, capital cost is amortised using a capital recovery factor).

OPEX

The following models the operational expenditure (OPEX) of a certain type of power generation capacity at a certain point of time. Let u_{mijtvp} be power output of plant *m*, vintage *v*, in year *t*, country *i*, block *p* on the load, and exported to country *j*. Let F_{mitv} be the corresponding operating cost, which varies with *v*, and θ_{jp} be the time interval of load block *p* within each year in the destination country. *Opex*(*t*) in year t is expressed as

$$Opex(t) = \sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{m=1}^{M} F_{mitv} * u_{mijtvp} * \theta_{jp} \qquad (1)$$

Carbon Emissions

The model considers carbon emissions of different types/technologies of power generation capacity and takes the cost of carbon emissions into consideration. Let ce_m be the carbon emissions per unit of power plant capacity of type *j* plant, and cp_t be the carbon price per unit of carbon

[6] Vintage indicates the time a certain type of capacity is built and put into use.
[7] This variable represents investment in new power generation capacity. Investment is considered done once the power generation facility has been constructed and not at the moment when investment decision is made and construction commences.

emissions in year *t*. The amount of carbon emissions produced are expressed as $\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m$, and carbon cost in year *t* is

$$CC(t) = cp_t * (\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m) \quad (2)$$

Cross-Border Transmission Cost

The costs of cross-border transmission come in two forms. One is the tariff paid to recover the capital investment and operational cost of the grid line. The other is the transmission loss, which could be significant if the distance of transmission is long. To model the tariff of transmission, let tp_{ijv} be the amount of new transmission capacity added between country *i* and *j* at year *v*. ct_{ijv} and co_{ijv} are the annualised CAPEX (with a 30-year contract and stipulated IRR embedded) and OPEX of the new transmission capacity, respectively. Let *TC*(*t*)be the total cost of cross-border power transmission in year *t*, and we have

$$TC(t) = \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T}(ct_{ijv} + co_{ijv}) * tp_{ijv} \quad (3)$$

Objective function

As discussed earlier in the methodology section, the objective is to minimise the total cost of electricity during the period of this study. The objective function is written as follows:

$$obj = \sum_{i=1}^{I}\sum_{v=1}^{T}\sum_{m=1}^{M} c_{miv} * x_{miv} + \sum_{t=1}^{T}\{Opex(t) + CC(t) + TC(t)\} \quad (4)$$

Constraint conditions

Optimising the above objective function is subject to the following constraints. Equation (5) shows a first set of constraints, which require total power capacity to meet total power demand in the region. Let Q_{itp} be the power demand of country *i* in year t for load block *p*.

$$\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{m=1}^{M}\sum_{v=-V}^{t} u_{mijtvp} \geq \sum_{i=1}^{I} Q_{itp} \quad (5)$$

The second one, shown in equation (6), states the constraint of load factor lf_{mi} of each installed capacity of power generation. Let kit_{mi} be the initial vintage capacity of type *m* power plant in country *i*.

$$u_{mijtvp} \le lf_{mi} * (kit_{mi} + x_{miv}) \tag{6}$$

The third constraint, shown in equation (7), says that power supply of all countries to a certain country must be greater than the country's power demand. Let $tl_{i,j}$ be the ratio of transmission loss in cross-border electricity trade between country *i* and country *j*.

$$\sum_{j=1}^{J}\sum_{m=1}^{M}\sum_{v=-V}^{t} u_{mijtvp} \cdot tl_{ij} \ge Q_{itp} \tag{7}$$

Equation (8) states that total supply of power of one country to all countries (including itself) must be smaller than the summation of the country's available power capacity at the time.

$$\sum_{j=1}^{J} u_{mijtvp} \le \sum_{m=1}^{M}\sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \tag{8}$$

The fifth constraint, shown in equation (9), is capacity reserve constraint. Let pr be the rate of reserve capacity as required by regulation. And let $p = 1$ represent the peak load block.

$$\sum_{i}^{I}\sum_{m=1}^{M}\sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \ge (1 + pr) * \sum_{i}^{I} Q_{it,p=1} \tag{9}$$

Specially, hydro-facilities have the so-called energy factor constraint as shown in equation (10). Let ef_{mi} be the energy factor of plant type *m* in country *i*. Other facilities will have $ef = 1$.

$$\sum_{p=1}^{P}\sum_{j=1}^{J} u_{mijtvp} \le ef_{mi} * (kit_{mi} + x_{miv}) \tag{10}$$

Development of power generation capacity faces resource availability constraint, which is shown in equation (11). Let $XMAX_{mi}$ be the type of resource constraint of plant type *m* in country *i*.

$$\sum_{v=1}^{T} x_{miv} \leq XMAX_{mi} \tag{11}$$

Lastly, power traded across border should be subject to the constraint of transmission capacities available at a certain point of time, which is specified in the model as follows.

$$\sum_{i=1}^{I} \sum_{j}^{J} \sum_{v=-V}^{t} \sum_{p=1}^{P} \sum_{m=1}^{M} u_{mijtvp} \leq \sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{v=-V}^{t} tp_{ijv} \tag{12}$$

CHAPTER 8

Assessment of Power Trade Benefits from Hydropower Projects in Lower Mekong River Basin

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The exchange of power between countries is regarded as economically beneficial since they offer opportunities for the optimum use of combined resources. This is especially the case when a hydropower-dominated supply system can be connected to a thermal power-dominated system due to the different and complementary characteristics of the two systems.

Hydropower in the Greater Mekong Subregion (GMS) has an enormous potential, on both large and small scale, to address regional energy requirement in significant capacity and the region has various experiences in regional power trading with the development of privately owned and financed cross-border hydropower project.

This research consists of three parts. The first part reviews the experience and lessons learned from the Regional Power Trade and Hydropower Development of Greater Mekong Subregion. It comprises two sections where section 3 presents an overview of power demand and supply in GMS countries, while section 4 reviews the hydropower development in the GMS. The second part focuses on determining benefits (economic benefit, and CO_2 emission reduction) accruing to each country by explaining the value of avoided generation costs and the annual cost of the hydropower project. This part is found in section 5 where the results of power benefit assessment are presented. The third part presents the key lessons learned and main challenges in GMS power trade and provides recommendation and policy implication for its smooth implementation. This part consists of sections 6, 7, and 8 where main the challenges and lessons are presented, followed by conclusions and recommendations.

The research found that the main mechanism for power trade in the GMS would be based on large-scale hydropower generation. To attract more investors and reduce investment risk in hydropower development, there is a need to refine investment costs, acquire hydrological data, and mitigate social and environmental impacts. Inter-governmental joint investments and the involvement of international financial institutions (IFIs) can also foster the necessary legal and legislative frameworks and enhance investment flow into an energy-export market. The Regional Power Coordination Center (RPCC) will play an important role in coordinating and accelerating the regional power trade for regional market rule comprising agreed rules and indicative planning priority of interconnection.

Keywords: hydropower, power trade, power supply benefit, power export benefit, economic benefit, Cambodia, Lao PDR, Myanmar, Thailand, Viet Nam, Guangxi, Yunnan, LMB, and GMS.

Introduction

Background

Energy cooperation in the Greater Mekong Subregion (GMS) began as part of the GMS Economic Cooperation Program launched in 1992. The GMS comprises Cambodia, the Lao People's Democratic Republic (Lao PDR), Myanmar, Thailand, Viet Nam, and the Guangxi Zhuang Autonomous Region and Yunnan Province of China.

Before 1992, at the start of the GMS program, the only significant power transmission links in the GMS were those between the Lao PDR and Thailand for the export of Lao PDR hydropower to Thailand. These consisted of double- and single-circuit 115 kilovolt (kV) lines to northeast Thailand from the Vientiane networks when the Lao PDR commissioned Nam Ngum 1 hydropower plant in 1971, and the single-circuit 115 kV line connecting the Lao PDR's southern grid to the Thai system in 1991 to deliver power from the Xeset hydropower plant (ADB, GMS-2012).

So far, power trade is only happening on a bilateral basis through transfer between the grid of producer and the consumer countries. The power being traded is mostly generated by hydropower plants and sold under power purchase agreements (PPAs) designed on a per project basis. Total electricity trade is 34,139 gigawatt-hour (GWh) in the GMS region where China, Lao PDR, and Myanmar are exporters while Thailand and Viet Nam are the main importers (ADB, RETA 6440- 2010).

While the first decade of subregional energy cooperation served primarily to advance planning and policy and institutional coordination, GMS energy cooperation also facilitated the implementation of high-priority power project with subregional impacts. Within the first decade, two hydropower plants in the Lao PDR exporting power to Thailand were implemented with private sector participation and ADB assistance (ADB, GMS-2012). For the second decade, the GMS program saw a quickened pace of project implementation by GMS governments with donor and development partner assistance and private sector initiative. Various other power generation and associated transmission projects in the GMS have also been developed. Among these are the generation and associated interconnection project in the Lao PDR and Myanmar that are intended for regional power trade, including the ongoing construction of the coal-fired Hongsa plant (1,800 megawatts [MW]), the various new hydropower capacity in the Lao PDR, and the completed Shewli-1 (600 MW) and Dapein-1 (240 MW) hydropower plant in Myanmar, which is now dispatching power to Yunnan province in China (ADB, GMS-2012).

At the moment, the framework for developing the GMS energy market integration (EMI) has taken through the Regional Power Trade Coordination Committee (RPTCC), which consists of two working groups—Working Group on Performance Standards and Grid Code, and Working Group on Regulatory Issues. The other approach of GMS regional power trade is to expect for the finalisation of the bidding that will decide who will host the Regional Power Coordination Center (RPCC), headquarter, the permanent, dedicated center envisioned to coordinate power trade in the GMS and to fully implement the Regional Investment Framework (RIF) for energy sector pipeline.

Objective

This paper aims to draw the lessons learned from two decades of cooperation of GMS power trade and interconnection. Its main purpose is to prove that hydropower could play an increasingly important role in the EMI of the GMS in the near future, serving as the answer to the rapidly growing demand for energy in the GMS countries while providing an alternative to dependency on fossil fuel. The result from this research will contribute to the EMI studies by providing policy analyses and recommendations to leaders and ministers at regional meetings, such as the East Asia Summit (EAS) Energy Ministers Meeting (EMM), the ASEAN Summit, and the EAS.

Structure

This paper consists of three sections. The first section focuses on the literature review by going through the experiences and lessons learned from the Regional Power Trade and Hydropower Development of Greater Mekong Subregion. The second section determines the benefits (focusing on net economic benefit, and carbon dioxide [CO_2] emission reduction) accruing to each country by explaining the value of avoided generation costs and the annual cost of the hydropower project. Finally, the third section explores the key lessons learned and main challenges in GMS power trade in order to provide policy implication and recommendations for the smooth implementation of EMI in the GMS region.

Methodology

This research uses Power Evaluation Model (PEM) for calculating economic benefit from avoided cost of generation incurred from hydropower replacement to thermal power plant. The PEM model was made by the Mekong River Commission's Basin Development Programme (MRC-BDP) in 2008 for the assessment of basin-wide development scenarios during Phase 2 (MRC-BDP 2, 2010). This research focuses on the assessment of the net economic power benefits from shared hydropower projects between exporter and importer countries in the GMS region. The methodology details are described in **Annex 1.**

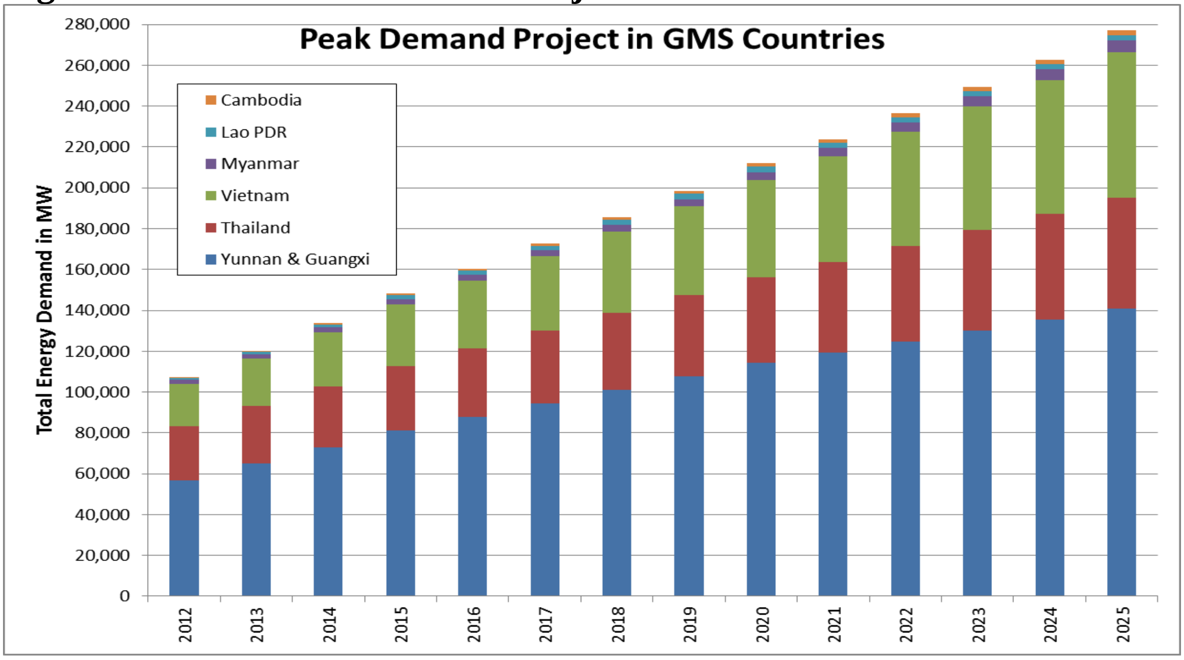
Overview of Power Demand and Supply in the GMS

Power Demand Projection in THE GMS

There are several factors driving electricity demand in the GMS. The rapid pace of export-led growth in the region comes on top of efforts to improve and expand electricity access in rural area, amid trends toward urbanisation, diversification of regional economy, and rapid population growth.

Peak demand in the GMS, which stood at 83 gigawatts (GW) in 2010, is expected to more than triple to 277 GW by 2025. Thailand has the largest power system and currently accounts for 29% of peak power demand. Viet Nam, the Guangxi Zhuang Autonomous Region, and Yunnan province each carry about 20% of the peak demand. Simulation undertaken for the latest update of the GMS Master Plan for power interconnection forecasts that by 2025, Thailand's share of peak power in the GMS will decrease to about 20%, while Viet Nam's rapid economic growth will increase its peak load share to a quarter of GMS peak load. The combined demand of the Guangxi Zhuang Autonomous Region and Yunnan Province in China will continue to account for about half of all the GMS peak demand. Thailand, Viet Nam, and China will account for 96% of the GMS peak demand by 2030 with greater reliance on gas and coal-fired electricity generation. Meanwhile, the power requirements of Cambodia, the Lao PDR, and Myanmar will similarly grow but are expected to retain only about 4% share of the subregion's overall power demand. The latter three countries have substantially smaller national power system but are expected to benefit from developing power export to the rest of the GMS, considering their substantial energy resource potential relative to their electricity needs (ADB, ICEM, GMS-2013).

Figure 8.1: Total Peak Demand Projections in GMS Countries

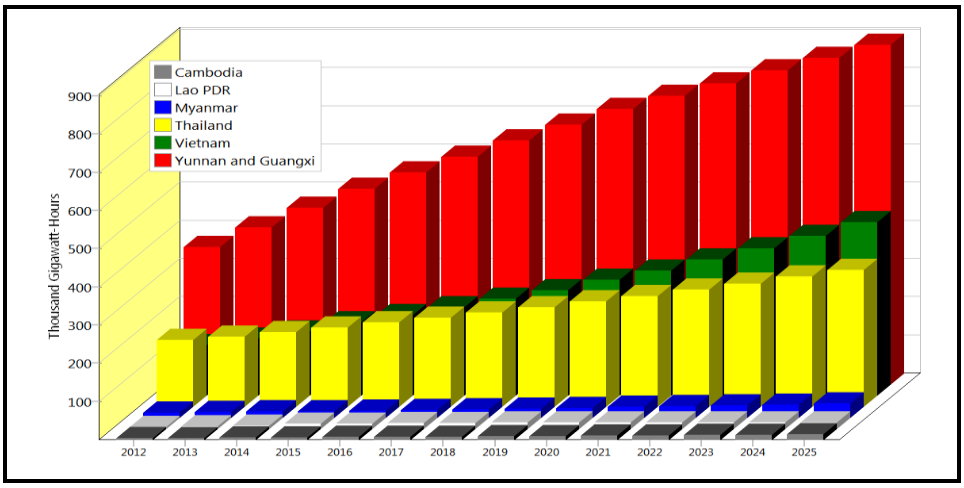


Source: ADB (2010).

Projected Energy Demand in the GMS

Electricity demand growth rates in many Mekong countries are among the highest in the world. The demand is mainly located in China, Thailand, and Viet Nam. By 2025, the total energy demand in the GMS will be 1,757 terawatt-hour (TWh) of which Yunnan and Guangxi of China account for 50%, Viet Nam for 25%, Thailand for 20%, and the remaining 5% shared by Myanmar, Lao PDR, and Cambodia (ADB, RETA 6440-2010).

Figure 8.2: Energy Demand Projection of GMS Countries (in GWh)



Source: ADB (2010).

GMS Energy Resources Endowment

In 2012, the energy resources in the GMS was estimated about 229 GW of annual hydropower potential along with proven reserve of about 1.2 billion cubic metres of natural gas, 0.82 million tons of oil, and 28 billion tons of coal. While the subregion is well-endowed with energy resources, these are unevenly distributed (Table 8.1).

Table 8.1: GMS Energy Resources Endowment

Countries/ Provinces	Hydropower (MW)	Gas (billion m^3)	Oil (million tons)	Coal (million tons)
Cambodia	9,703	N/A	N/A	10
Yunnan	104,370	N/A	N/A	23,994
Guangxi	17,640	N/A	173	2,167
Lao PDR	17,979	N/A	N/A	503
Myanmar	39,669	590	7	2
Thailand	4,566	340	50	1,239
Viet Nam	35,103	217	626	150

Note: N/A = not applicable
Source: ADB (2012).

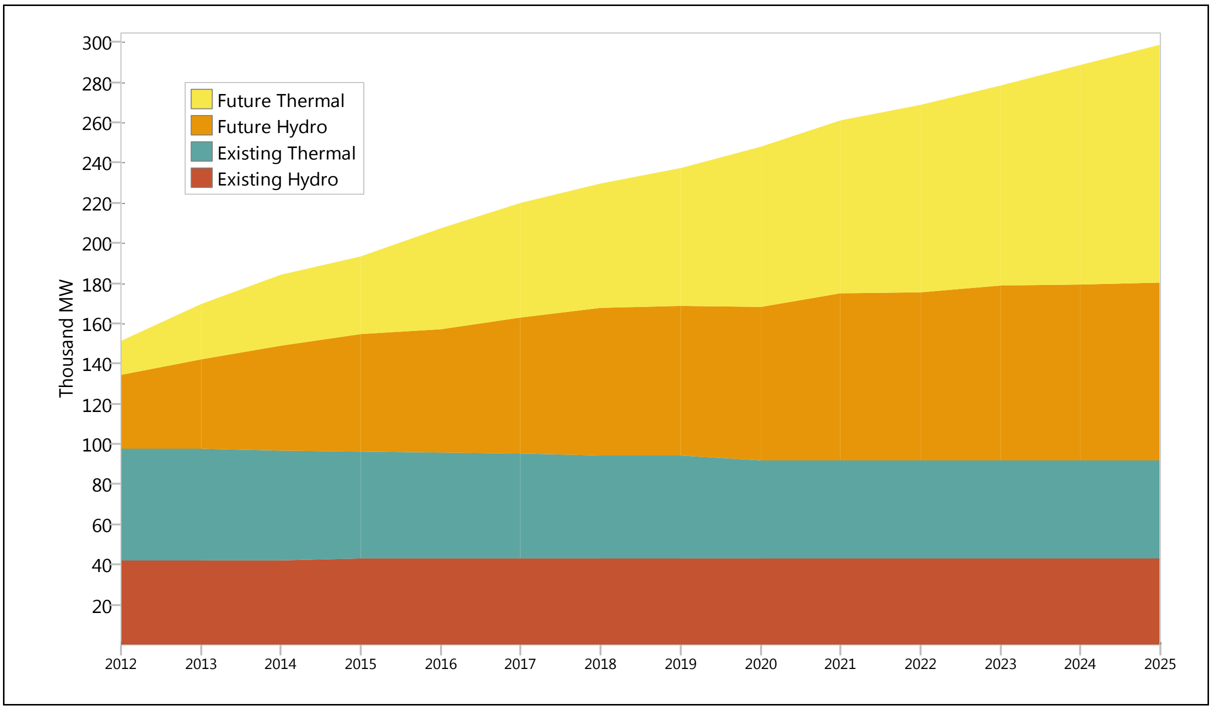
The Lao PDR, Myanmar, Viet Nam, and the two China provinces account for 94% of the hydropower resources in the region. The hydropower potential of the Lao PDR and Myanmar is substantial compared to their size and expected power need, while Viet Nam's hydropower potential is concentrated in Northern Viet Nam. Myanmar, Thailand, and Viet Nam possess natural gas deposits, Viet Nam has mostly oil reserves, and Yunnan Province of China holds the main coal deposit. Cambodia, Thailand, and the two China provinces have mainly been net energy importers, while the Lao PDR, Myanmar, and Viet Nam are net energy exporters to other GMS countries and the rest of the world. Similarly for electric power, the Lao PDR and Myanmar have been generating electricity for export beyond the supply requirement of their grid-connected domestic consumers (ADB, GMS-2012).

Development of The Power Sector in The GMS

Total installed generation capacity is projected to almost triple in the GMS over the period from 2012 until 2025 while the number of thermal and hydropower plants is expected to double over this period. Nationally, the projected capacity expansion is dominated by growth in Yunnan and Guangxi, where installed capacity is expected to more than double—from 53 GW in 2012 to 136 GW by 2025—representing 40% of the total increase across the GMS.

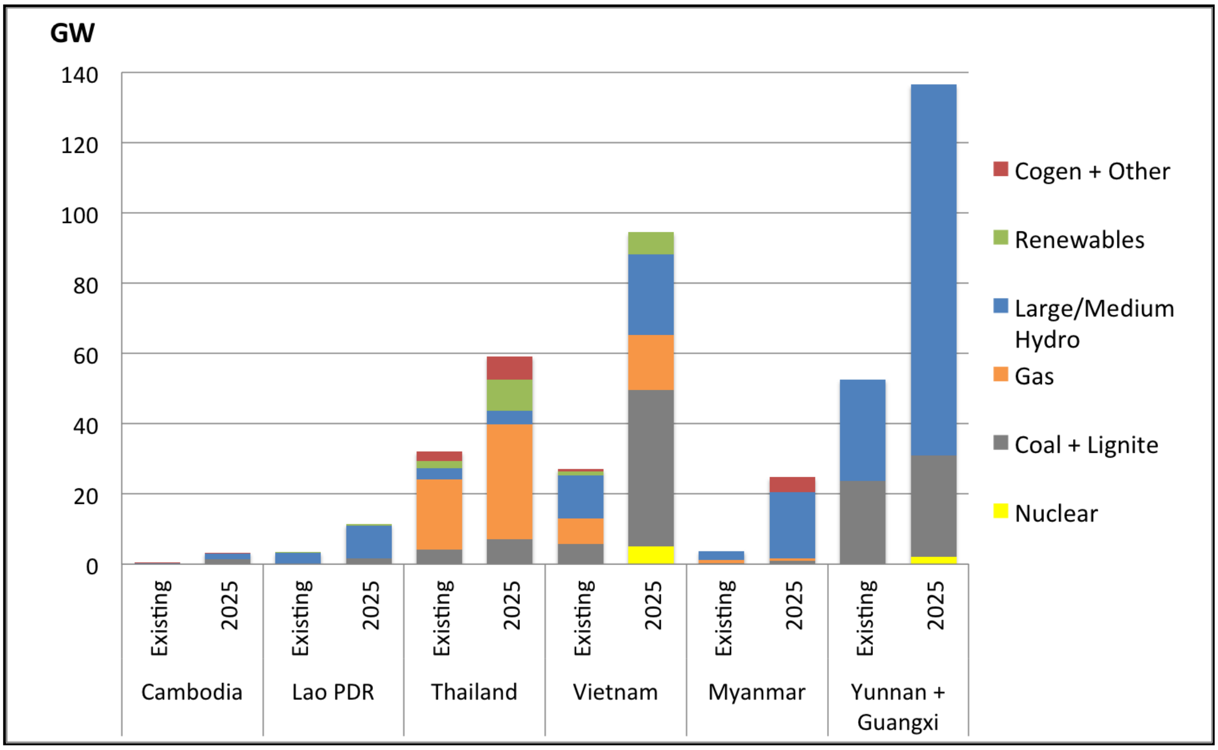
The projected expansion in large hydro capacity is largely due to planned projects in Yunnan, which represents an increase in hydro installed capacity of 77 GW or 69% of the total increase in the GMS. Installed large hydro capacity in Myanmar is projected to rise by 16 GW, in the Lao PDR by 15 GW, and in Viet Nam by 11 GW (ADB, RETA 6440-2010).

Figure 8.3: Installed Capacity Projection in the GMS by 2025 (without data from Myanmar)



Source: ADB (2010)

Figure 8.4: Projected Installed Capacity by Country in the GMS, Current PDPs Scenario



Note: GW = gigawatts, PDPs = power development plans
Source: ICEM and ADB (2013)

The technology with the largest expansion in both installed capacity and in number of plants is large hydro, followed by coal-fired plants. While renewables capacity grows more rapidly in percentage term than either of these, the absolute increase in renewables capacity is lower than those of these technologies.

Table 8.2: Projected Installed Capacity by Technology in the GMS, Current PDPs Scenario

Fuel Type	Existing (2012)		**Projected (2025)**		**Increased (2012-2025)**		
	MW	# Plant	**MW**	**# Plant**	**MW**	**%**	**# Plant**
Nuclear	0	0	7,160	4	7,160	0	4
Coal + Lignite	34,058	41	84,341	83	50,283	148	42
Gas	27,959	39	52,287	54	24,328	87	15
Large hydro	49,727	116	160,963	254	111,236	224	138
Renewables	3,533	n.c	16,475	n.c	12,942	366	n.c
Cogen + Others	3,689	16	8,006	6	4,317	117	-10
Total	**118,966**	**212**	**329,232**	**401**	**210,266**	**157**	**18**

Note: MW = megawatts, n.c = Not Count, PDPs = Power Development Plans
Source: ICEM and ADB (2013)

Review of Power Demand and Supply in Yunnan and Guangxi provinces

The electricity consumption per capita (kWh/person) in China is the highest among GMS countries. In 2011, the electricity consumption per capita was 2,600 in Yunnan and 2,394 in Guangxi. The peak demand of Guangxi and Yunnan will be 140 GW in 2025 with 40 GW export to Guangdong. The need for new additional capacity is about 3,500 MW per year. Although Yunnan has huge potential of hydropower, it will not be sufficient to cover the demand up to 2025.

The total supply for Guangxi in 2012 was 115.4 TWh with a peak demand of 20 GW (an increase of 3.8% and 8.1%, respectively, from 2011). By 2030, supply is projected to increase to 396 TWh and peak demand to 60.6 GW (an average annual increase of 7.5% and 6.7%, respectively). Total installed capacity within Guangxi in December 2012 was 30.4 GW. By 2030, this is projected to increase to 86 GW installed capacity within Guangxi with a 19

GW imported capacity. The largest increase will be in nuclear generation (from zero to 20 GW) and in thermal and gas generation (from 15 GW to 37 GW).

Yunnan currently has 10 coal-fired power plants with total installed capacity of 11.2 GW, and 14 hydropower plants with total installed capacity of 13.6 GW. By 2025, these will increase to 11 coal-fired plants with total installed capacity of 12.4 GW, and hydropower plants with total installed capacity of 88.7 GW (ADB, ICEM, GMS-2013).

In China, the investment cost of coal-fired steam thermal power plant is lower than in other GMS countries, but exposed to restrictions due environmental concern. Export to other GMS countries based on coal-fired power supply is not realistic. China will have a very limited export role except for local situations where there is temporary power surplus or for purposes of cooperation. The promising large volume of power export from China to Viet Nam does not look realistic. China has already imported hydropower from Myanmar and planned to import more hydropower generated from Myanmar and the Lao PDR. The import will allow China to save coal, reduce CO_2 emission, and to reach the target of supplying power to Guangdong (ADB, RETA 6440-2010).

Review of Power Demand and Supply in Thailand

The electricity consumption per capita in Thailand was 2,180 kWh/person in 2011.Thailand will require 54 GW by 2025, which is about 2,500 MW increase per year. In 2012, the country’s demand was 26.12 GW. By 2030, the demand forecast is 52.25 GW. About 80% of electricity produced in Thailand comes from natural gas. A higher proportion of imported liquefied petroleum gas (LPG) is needed as Thailand’s production of natural gas is insufficient for future requirements. Natural gas used in Thailand primarily comes from three sources: the Gulf of Thailand, 79%; Myanmar, 18%; and 3% imported as liquefied natural gas (LNG) from countries like Indonesia, Nigeria, Peru, Qatar, and Russia. However, the worst-case scenario prediction made by Economic Intelligence Center (EIC) estimates that the Gulf of Thailand will run out of natural gas by 2020. There are also risks from the possible failure to renew gas contract with Myanmar, which should end by

2030, as Myanmar's electricity consumption needs are also growing fast. Although Thailand has plans to import natural gas through pipeline from Cambodia, these plans still lack certainty from either government. Thus, it appears that Thailand will have to rely on importing a lot of LPG (SCB-2013).

Such supply risk is mitigated through diversification of generation mix (coal, nuclear, in addition to natural gas), power import sources (Lao PDR, Myanmar, Malaysia, Cambodia, and China), and fuel import sources. Significant level of power dependency is 14% of peak demand imported in 2025 (Power Development Plan 2010-Revision 2), of which 5.5 GW is from the Lao PDR and 1.9 GW from Myanmar. Going beyond 15% would require a careful analysis of balance between benefit and risks. Power import will reduce the use of natural gas and coal (ADB, RETA 6440-2010).

Review of Power Demand and Supply in Viet Nam

In Viet Nam, the electricity consumption per capita was 1,228 kWh/person in 2011. The peak demand will increase by 4,000 MW per year in 2025 to reach 71 GW. Viet Nam's power demand will catch up with Thailand's demand in 2017. The total installed capacity of power plant will be 75 GW by 2020 and 94 GW by 2025. Full national hydropower potential will be put in operation before 2025 by domestic power demand, especially priority multi-purpose projects such as flood control, water supply, and electricity production that will bring the total installed capacity from 9.2 GW at the present to 17.4 GW by 2020.

By 2020, electricity generation capacity using natural gas will be 10.4 GW, producing about 66 TWh of electricity, and accounting for 20% of electricity production. It is expected that in 2030, the total capacity of thermal power plant using natural gas will be 11.3 GW, producing 73.1 TWh of electricity, and accounting for 10.5% of total capacity. To diversify fuel source for electricity production, Viet Nam will develop power plants using LNG. In 2020, electricity generation capacity using LNG will be about 2 GW, and by 2030, the capacity will be about 6 GW (Government of Viet Nam, 2011).

Viet Nam has been considering developing nuclear power for peaceful purposes based on modern, verified technology since 1995, and firm proposals surfaced in 2006. However, in January 2014, it was reported that Viet Nam had decided to delay construction by six years. The first nuclear power plant will put in operation by 2020. By 2030, installed capacity of nuclear power will be 10.7 GW, producing 70.5 TWh (accounting for 10.1% of electricity production).

Viet Nam will make use of domestic coal resource for the development of thermal power plants and will prioritise the use of domestic coal for thermal power plant in the Northern region. By 2020, the total coal thermal power installed capacity will be 36 GW, producing 156 TWh (accounting for 46.8% of total electricity production), and consuming 67.3 million tons of coal. By 2030, the total installed capacity for coal power plant will be 75 GW, producing 394 TWh (accounting for 56.4% of total electricity production), and consuming 171 million tons of coal. Due to the limitation in domestic coal production, building and putting power plants using imported coal into operation from 2015 is to be considered. Viet Nam has become a net coal importer by 2012. There are plans to reduce gradually its coal export.

Viet Nam currently exports power to Cambodia due to shortage of supply, with economic power exchanges as the main rationale. Viet Nam planned to import hydropower, especially from the Lao PDR and then Cambodia and China. It is expected that in 2020, imported electricity capacity will be about 2.2 GW and approximately 7 GW in 2030. The level of power dependency is 7% of the peak demand which was reported in the Viet Nam National Master Plan for Power Development Plan 2011-2020 with the vision to 2030 (Master Plan VII). The maximum level of power import was accepted with 10% of peak demand and imported-power will reduce imports of coal and natural gas.

Review of Power Demand and Supply in Lao PDR

Electricity demand growth in the Lao PDR registered a significant increase in the past few years. In 2011, the electricity consumption was 402 kWh/person, produced energy per capita was 1,570 kWh/year, and exported energy per capita was 1,360 kWh/year. The major consumptions come from mining industries, manufacturing, commercial business, services, and rural electrification projects. To date, there are two independent network systems in the Lao PDR—the domestic supply network (Electricité du Laos [EDL], domestic independent power producer [IPP], and off-take from exporting IPP), and the exporting network (exporting IPP) to neighbouring countries, i.e., Thailand, Viet Nam, and others.

By 2021, the domestic demand forecast will be about 3,570 MW with the annual average growth of capacity at 235 MW. In the Lao PDR, hydropower plants provide electricity for both domestic consumption and for export to Thailand and Viet Nam. The total installed capacity was 2,570 MW in 2011 (all from hydro) and forecast to reach 12,500 MW in 2020. An additional 2,623 MW of capacity is expected, involving 12 power plants for both domestic consumption and export, and these are in various stages of construction. In addition, 60 new hydropower plants are in various stages of study, approval, and design. By 2020, when all of the 12 projects presently under construction have been completed, it is expected that the Lao PDR will have harnessed about 8,100 MW of its 20,000 MW of potential capacity. Lao PDR has about 13,5000 MW of hydropower potential with cost lower than US$0.05/KWh that has been planned primary for export to Thailand and Viet Nam, and possibly to China (EDL-DOE, 2011).

As to coal and lignite, the coal reserve of the Lao PDR is estimated to be about 600-700 million tons, occurring mostly as lignite with smaller amount of anthracite. In 2011, the first lignite-fired power plant (Hongsa Lignite Thermal Power Plant) was put under construction and is expected to be completed in 2016. The total installed capacity of this plant is 1,878 MW of which 1,473 MW will be exported to Thailand, while the remainder will be used for domestic supply. Moreover, the Kaleum thermal power plant with installed capacity of 600 MW is also considered for export (ADB, ICEM, GMS-2013).

Review of Power Demand and Supply in Cambodia

Electricity demand in Cambodia is growing rapidly at an annual average growth rate of 16% for electricity supply and 18% for electricity demand in the past five years from 2009 to 2013. In 2012, the annual electric energy consumption per capita was 190 kWh and electricity supply was a mix of

20% imported electricity (11.8% from Viet Nam, 8.1% from Thailand, 0.1% from the Lao PDR), 46% heavy fuel oil, 31% hydropower, 2% coal, and 1% from other sources. The energy demand is projected to reach 2,750 MW by 2020. As of January 2014, the total installed capacity was 1,662 MW including that of a new coal power plant of 100 MW. Cambodia is currently eager to increase its electricity generation capacities from hydropower and coal power plants to decrease its import dependency and reduce the generation for fossil fuel. Cambodia has a hydropower potential of about 10,000 MW; only seven hydropower plants with a total capacity of 1,326 MW were put in operation and some are under construction, which are expected to be completed by 2017. There is a potential of 2,600 MW of hydropower projects with a cost lower than US$0.05/kWh, located on the mainstream of Mekong River that can be exported to Viet Nam and Thailand. Due to fisheries, resettlements, and land issues; lack of transparency; and lack of environmental and social impact assessment and community consultations, this large-scale potential is highly controversial and, therefore, is unlikely to be developed (ADB, RETA 6440-2010).

Cambodia has planned to install 1,000 MW of coal power plant by 2020. The first coal-fired power plant with a capacity of 100 MW was put in operation in February 2014. Other plants with a total of 400 MW capacity are expected to complete the 100 MW target for each year from 2014 until 2017. The second phase was planned with 500 MW and the expected operation is from 2017 until 2020. Another coal-fired power plant (1,800 MW) is planned to be built in Cambodia’s border under a US$3 billion joint-venture agreement with Ratchaburi Electricity Generating Plc. This project has been planned to sell 90% of the power generated (1,600 MW) to Thailand and the remaining 10% will be used for domestic supply (EAC, 2013).

Review of Power Demand and Supply in Myanmar

The electricity demand in Myanmar is increasing rapidly with an average increase of 15% between 2013 and 2016. In 2013, power demand was 1,850 MW with total generation at 1,688 MW. The demand is projected to reach 19,216 MW with installed capacity of 24,981 by 2030. For its energy supply, the country primarily relies on hydropower (75%), followed by gas (22%), and coal (3%). Myanmar has abundant energy resources, particularly hydropower and natural gas (ADB, GMS- 2012).

Myanmar has identified 92 potential large hydropower projects with a total installed capacity of 46,101 MW. Only 20 hydropower plants with a total capacity of 2,780 MW have been commissioned by 2013. The Ministry of Electric Power (MOEP) is planning to build another 13 hydropower plants by 2020 with a total capacity of 2,572 MW while an additional 44 projects are planned as joint ventures with foreign investors, totalling approximately 42,146 MW. Electricity produced by hydropower is considered very cheap compared to other alternative sources. There are 28,000 MW of hydropower potential at a cost of just about 2.5 cents in US dollar per kWh, some of which have already been exported to China, and more exports are being planned for China, Thailand, India, and Bangladesh (Doran, *et al*., 2014).

There are 33 major coal deposits with estimated total reserves of 488.7 million tons in various categories. Only 1% of this estimate potential, however, has been confirmed. According to the 30-year plan prepared in 2007, coal production is scheduled to increase by 16% annually reaching 2.7 million tons by 2016 and 5.6 million tons by 2031. In 2011, a total of 0.7 million tons of coal was used domestically, of which 42% was for power generation, 52% for cement and other industrial uses, and 4% for household (cooking and heating) use. The first coal-fired plant with 120 MW was completed in 2002. Myanmar has planned to construct three more coal power plant with a total capacity of 876 MW (ADB, GMS-2012).

Myanmar's hydrocarbon reserves are predominately in the form of natural gas, the reserve of which is estimated to be 334 BCM. In 2010, Myanmar exported 8.81 BCM of natural gas, significantly more than that of Malaysia at 1.45 BCM, and follows Indonesia with 9.89 BCM. Myanmar, however, is a net importer of oil. Domestic gas demand in 2011 was about 60 BCM of which 60% was supplied to 10 gas-fired power plants. Another 10 gas-fired power plants with a total capacity of 1,720 MW are planned to be put into operation between 2014 and 2017 (ADB, GMS-2012).

Review of Hydropower Development in the GMS

As of 2012, there is some 49,000 MW of hydro capacity in the GMS, of which 20,000 MW is in the Lower Mekong Basin (LMB) countries (Table 8.3). According to current power development plans (PDPs), this is set to triple by 2025.

Table 8.3: Overview of Hydropower Development in the GMS

	Installed Capacity			**Number of Projects**		
	Existing	PDP	Capacity additions	Existing	PDP	Capacity additions
	2012	2025	2013-2025	2012	2025	2013-2025
	[MW]	[MW]	[MW]	[#]	[#]	[#]
Cambodia	206	1,658	1,452	2	9	7
Lao PDR	3,150	9,456	6,306	14	53	39
Thailand	2,675	2,675	0	6	6	0
Myanmar	2,660	18,756	16,096	19	39	20
Viet Nam	11,711	17,002	5,291	46	85	39
Total LMB	20,402	49,548	29,145	87	192	105
Guangxi	13,581	88,672	75,091	14	39	25
Yunnan	15,244	16,844	1,600	14	15	1
Total GMS	49,227	155,064	105,836	115	246	131
Mekong	3,652	10,786	7,134	18	60	42
Others	45,575	144,277	98,702	97	186	89

Note: GMS = Greater Mekong Subregion, LMB = Lower Mekong Basin, MW = megawatts, PDP = power development plan (Note: excludes pumped storage and small hydro);
Source: ICEM and ADB (2013).

As shown in Table 8.3, the future development of hydro in the region is also very uneven—at the one extreme, no new large hydro projects are likely to be developed in Thailand, while at the other extreme, projects at 75 GW are under development in Guangxi, and 16 GW in Myanmar. The pace of hydro development in Viet Nam has already slowed, as all the large projects have now been developed, and planners are looking to the Lao PDR for additional hydro projects to provide peaking power where it competes with Thailand for additional export projects. Whether this is achievable will depend on the following three factors:

- If the costs of hydro generation will continue to be significantly below that of peaking power supplied by gas;
- If the incremental finance requirement can be mobilised (the typical hydro investment for new projects is US$2,400/kW; that for CCGT is only US$850/kW); and
- If and when the increasing public opposition to hydro power due to environmental and social issues—which already effectively prevented the further development of large hydro projects in Thailand—will expand to the other countries in the region.

The extent to which this large hydro-export potential can be realized will depend on the extent to which projects are commercially feasible. This depends on the following four criteria:

- Potential investors make a financial return that reflects the risks assumed.
- Projects can be financed.
- Host country governments can extract adequate resource rents.

Importing countries can buy hydro power at lower cost than the next best alternative (which in the case of both Thailand and Viet Nam will likely be gas combined cycle thermal generation).

The four parties involved in a large export project—the developer, the lenders, the host country, and the importing country—all have conflicting interests. The extent to which a commercially satisfactory compromise can be reached for all of the identified potential projects is difficult to judge. There are a number of examples in the international experience where hydro export projects are effectively blocked because one or more of the four parties have unreasonable expectations. One classic example is the unreasonable expectation of the Government of Nepal about the value of peaking power from Nepalese hydro export projects into the Indian power market—expectations that constitute one of the main causes for the lack of progress in implementing such projects. By contrast, the Lao PDR has been much more successful in finding the right balance of these commercial interests, though many claim that the environmental and social interests have been inadequately reflected in Lao PDR’s export projects (ADB, ICEM, GMS-2013).

Trends in Hydropower Development in The GMS

Several trends can be identified from the inventory of proposed projects. The installed capacity of projects is increasing, from an average of 428 MW (covering all GMS countries) in existing projects to 808 MW for all projects added between now and 2025. In Viet Nam, the average size is expected to decline from 255 MW to 136 MW (Table 8.4). In Guangxi, the average project size will increase from 970 MW to 3,000 MW (ADB, ICEM, GMS-2013).

For many reasons, the next decade is likely to see significant development of pumped storage. In Viet Nam, while conventional large hydro additions are forecast in its Power Development Plan at some 5,200 MW, another 4,200 MW of pumped storage is envisaged. This is being driven by three main factors. *First*, with prospects for additional domestic gas seen as uncertain, pumped storage is seen as considerably less expensive than combined cycle gas turbines (CCGTs) using imported LNG. *Second*, with many base load imported coal and nuclear projects seen as necessary beyond 2020, and with increasing daytime air conditioning load, pumped storage is seen as a suitable balance mechanism to meet daily load variations. This is unlikely to be seen in Myanmar, the Lao PDR, and Cambodia where domestic load will remain modest compared to potential export markets. And *third*, the environmental impacts of pumped storage are seen as relatively manageable, particularly where an upper reservoir—whose active storage and surface area can be quite small—can be sited adjacent to a large existing conventional hydro project (ADB, ICEM, GMS-2013).

Table 8.4: Average Installed Capacity (MW)

Country	2012	2015	2020	2025	All New
	[MW]	[MW]	[MW]	[MW]	[MW]
Cambodia	103	182	203	184	207
Lao PDR	225	156	167	178	162
Thailand	446	446	446	446	
Myanmar	140	118	117	481	805
Viet Nam	255	228	205	200	136
Total LMB	235	197	186	258	278
Guangxi	970	2,391	2,345	2,274	3,004
Yunnan	1,089	1,089	1,123	1,123	1,600
Total GMS	428	624	583	630	808
Mekong	203	158	171	180	170
Others	470	742	722	776	1,109

Note: GMS = Greater Mekong Subregion, LMB = Lower Mekong Basin, MW = megawatts
Source: ICEM and ADB (2013)

Hydropower Development and Implementation Models

The additional 100 GW hydro capacity from 2013-2025 represents an enormous financing requirement. Even excluding the capacity in China, the remaining 29 GW in LMB countries represent an investment requirement of some US$70 billion. Even if the environmental impacts can be mitigated, mobilising this investment will be formidable. Notwithstanding IPP interest in a number of hydropower projects in the region, mobilising private capital for thermal projects is much easier; with much shorter construction periods and fewer environmental obstacles, the risk perception of hydropower projects remains even for projects where tunnelling risk is relatively low (Doran and Christensen, 2014).

The first implementation model for large projects is the public-private partnership (PPP), where a host country government has a significant equity stake, and which enables access to international financial institutions (IFIs) for a significant part of the debt (as in the case of Nam Ngum 3, to be financed by ADB), or access to partial risk guarantees (PRGs) (as in the case of Nam Theun 2). It is a policy of the Government of Lao PDR that it should have a share in the equity of electricity projects developed under a concession agreement (though one of the issues is the extent to which it has the ability to bear the equitable share of the up-front development costs, which some memoranda of understanding (MOU) allow to be deferred to financial closure (Doran and Christensen, 2014).

A typical equity consortium involves several parties, in the case of export projects, they most often include entities from the country to which the electricity will be exported. IFI participation in such project (or even participation in equity from the International Finance Corporation (IFC) or the ADB private finance arm) provides comfort to both lenders and equity holders, lowering the risk premiums for the remaining finance and equity tranches.
The involvement of the IFIs is contingent upon meeting their safeguards requirements, which include, among others, ensuring certain minimum standards for adequate safeguard provisions for project-affected persons in project areas. Thus, securing IFI finance for such PPPs is not only a matter of finance availability but also of mitigating actual or perceived reputation risks (an issue that is particularly sensitive in the case of the World Bank). The recent experience of the World Bank in the region, for example, in the case of the 260 MW Vietnamese Trung Son Hydropower Project, suggests that careful preparation, engagement of the local community, and complete transparency in the appraisal process enabled bank financing without much difficulty, and lead to successful and sustainable projects. It seems likely that in Viet Nam, the World Bank will be seen particularly as a source of funding for pumped storage projects.

The World Bank's safeguard requirements on downstream impact have particular relevance to the Mekong River Mainstream projects. These bank-financed investments involve water abstraction, release of water or material into water, or hydrological impacts (regardless of scale) on a water body that is shared by two or more countries (aquifers, open seas excluded; except in the rehabilitation of an existing scheme); and require notification and no objection from downstream residents with riparian rights. If one or more of the downstream parties do object, then at the very least, time-consuming studies will need to be conducted to refute or concur with their grounds for objection, before bank financing can be approved (MRC-SEA, 2010).

The second implementation model relies entirely on commercial financing, without IFI participation. For example, the Xayaburi project (1,260 MW) in the Lao PDR, which exports to Thailand, is financed by a consortium of Thai commercial banks whose equity participation includes Thai and Laotian private companies, plus the Government of Lao PDR. A number of domestic hydropower projects in Cambodia are also being developed by Chinese companies. This implementation model has the advantage (from the narrow perspective of investors) that they do not need to be concerned about IFI safeguards. Thus, backed by export credit and by increasingly strong private commercial banks, a new generation of IPP hydropower project developers based in Thailand, Malaysia, and China is gradually displacing IFIs and IPP developers based in Organisation for Economic Co-operation and Development (OECD) countries, which are increasingly encumbered by nongovernment organizations (NGOs) vocally opposed to hydropower development (EDL, 2011).

This is exemplified by Cambodia. All seven hydropower projects—(i) Kamchay, 193 MW, completed in 2011; (ii) Kirriom III, 18 MW; (iii) Lower Russei Chrum, 338 MW; (iv) Stung Tatay, 246 MW; (v) Stung Atay, 120 MW; (vi) Lower Sesan II, 400 MW; and (vii) Stung Chay Areng, 108 MW—are being developed by Chinese companies (EAC, 2013).

Financing Requirements for Hydropower Development in the GMS

A bankable power purchase agreement (PPA) is highly essential in considering commercial feasibility, the main determinant of bankability being the credit standing of the buyer. Fortunately, the two main potential buyers, the Electricity Generating Authority of Thailand (EGAT) and Electricity Viet Nam (EVN), have relatively good credit ratings and customer tariffs that are not excessively below marginal costs. The length complexity of PPA will be a function of the extent of involvement of foreign investors as well as the size of the project. The Nam Theun 2 (NT2) PPA (whose equity investors include the French EDF, Italian, and Thai companies) runs to over 600 pages. Also, this NT2 PPA would not have been signed without the partial risk guarantee (PRG) of the World Bank (Fraser, 2010).

The question of the remaining headroom for sovereign guarantees is difficult to assess, particularly in the case of the Lao PDR, and their absence will affect the investment supply cost through higher interest rates. In 2010, ADB financed (US$465 million) for the Nam Ngum 3 project, US$350 million will be provided without sovereign guarantees. The remaining US$115 million is sovereign loan (Fraser, 2010).

However, the entry into Lao PDR, Cambodia, and especially Myanmar (where the undeveloped potential is the largest in the region) of the Chinese EXIM Bank, and Chinese developers, is changing earlier perceptions of the difficulty of financing large hydro projects in the region in the absence of IFI finance. The NT2 project showed that large hydro projects could, indeed, be successfully implemented by the private sector (albeit with PRGs from IFIs). That the role of ADB and the World Bank will inevitably continue to decline in the GMS as a source of finance for generation projects should not, however, be seen as a failure of these institutions, but rather as a success—having fulfilled the role of an early catalyst—since their financial resources are much better directed to rural electrification, energy efficiency, and transmission & distribution, where commercial financing alternatives are not available.

Trends with Multilateral, Bilateral and Projects Specific Agreement in Power Trade

Governments in the GMS signed an Intergovernmental Agreement on Power Interconnection and Trade in 2003. Subsequently, a ‘road map’ to implement the agreement was prepared. This road map builds on a series of bilateral MOUs and agreements developed by the GMS governments over the past two decades to extend cross-border power trade between their respective countries. These bilateral MOUs authorise respective power entities in each country to negotiate PPAs for specific projects, which fit within the quantum of power under the bilateral MOU.

So far, Thailand has signed bilateral MOUs to buy up to 11,500 MW from its neighbor countries. In 2007, Thailand signed an MOU with the Lao PDR to purchase 7,000 MW, with China for 3,000 MW, and with Myanmar (MOU now expired) for 1,500 MW. Thailand and Cambodia also signed an MOU on power cooperation with unspecified capacity. Power exports from Thailand to Cambodia were 95 MW in 2013 and will increase to 135 MW in 2014. Thailand is projecting 5,427 MW in power interconnection purchases during the period 2013-2019, mostly from the Lao PDR, comprising 2,111 MW from completed projects and 3,316 MW from signed PPAs and projects under construction (RPTCC 15th, 2013).

Based on an MOU between Viet Nam's Ministry of Industry and Trade and Lao PDR's Ministry of Energy and Mines signed in March 2008, Viet Nam would invest in 31 projects with total installed capacity of 5,000 MW where a large part of the energy produced from these projects will be exported to Viet Nam. In the last Viet Nam PDP (Master Plan VII), the total power exchange with its neighboring countries, especially with Lao PDR, Cambodia, and China, is expected to be 2,200 MW in 2020 and imported electricity capacity will be approximately 7,000 MW in 2030. In May 2009, the Eletricité du Viet Nam and Electricité du Cambodge signed an electricity trading contract that Viet Nam would sell electricity to Cambodia at a capacity of 200 MW in 2010. The Government of Cambodia also agreed to sell its surplus power from hydropower project to Viet Nam during the wet season, but without indicating the capacity (ADB, RETA 6440-2010).

China is actively strengthening its cooperation with Viet Nam, Lao PDR, Myanmar, Thailand, and Cambodia with the objective of optimising resources allocation and utilisation. Since 2004, the China Southern Power Grid (CSG) has exported 1,100 MW to Viet Nam, 24 MW to the Lao PDR, and imported 483 MW from Myanmar. CSG indicated that it will import 10,000 MW from Myanmar between 2012 and 2030 of which 5,000 MW will come from hydropower in Irrawaddy and Salween River Basin. In June 2013, China and Thailand signed the MOU on Power Purchase Program from China to Thailand with transmission through Lao PDR (ADB, Laos-2011).

Myanmar signed an MOU with Thailand in 1997 for the trade of 1,500 MW of electricity, which expired in 2010 and has not been renewed. Thailand is reported to be in negotiation to purchase up to 10,000 MW of hydroelectricity from Myanmar over an unspecified time period. This MOU is linked directly to Salween dam projects, five proposed dam along the Salween River, which would have a combined capacity of more than 18,000 MW. Specifically, Thailand will receive most of the power of 7,110 MW from Tasang dam, which is planned along its border with Myanmar. Thailand, through its generating authority, the EGAT, is also planned to receive the majority of power generated of 1200 MW from Hatgyi dam, which is currently under construction and is expected to supply the Thai national grid by 2019. The Weigyi dam, which has a total capacity of up to 5,600 MW, is also planned to export to Thailand.

The Ministry of Power, Energy and Mineral Resources of Bangladesh is reported to negotiate for the purchase of 500 MW of hydropower from Myanmar by 2017. However, apart from this pending agreement, no other broad power trading MOUs are reported to be under consideration.

India’s National Hydroelectricity Power Corporation (NHPC) signed an MOU with the Government of Myanmar in 2004 for the development of Tamanthi dam in Chindwin River with installed capacity of 1,200 MW. Of this generated hydropower, 80% will be supplied to India. A new agreement was signed in 2008 for a joint venture between the NHPC and Myanmar Hydroelectricity Power Department to develop the Tamanthi and Shwesayay dams.

So far, China is the largest financier of hydropower in Myanmar and has a number of MOUs signed for various power-trading agreements. Chinese state-owned enterprises are publicly involved in nearly every large-scale hydropower project, either at the advanced planning stage or under construction in Myanmar. Together, these projects represent 31,451 MW of potential generating capacity, a significant percentage of which will be exported to China. The largest of these project-specific MOUs was signed in 2007 between the Government of Myanmar and China Power Investment Corporation for the implementation of seven large dams along Irrawaddy, Mali, and N’Mai rivers in Kachin state for a total of more than 17,000 MW. However, the implementation of these projects has met resistance. The largest of the proposed projects in this cluster, the 6,000 MW Myitsone dam, has been suspended since 2011 by order of the Government of Myanmar as a result of mounting pressure from local population and for environmental impact concerns (ADB, 2013).

Results of Power Benefit Assessment

Using the intended distribution of power to the different countries, two sets of values were calculated. One is the annual power production intended for use in each country. The other is the annual power export from the host country to other countries. Table 8.5 presents the results from the annual power supply benefits assessment.

Table 8.5: Results of Power Supply Benefit Assessment

POWER SUPPLY (GWh)					
SCENARIO (year)	**LAO PDR**	**THAILAND**	**CAMBODIA**	**VIET NAM**	**TOTAL**
2015	4,265	10,205	207	12,314	26,991
2030	15,025	55,474	10,120	30,279	110,898
BENEFIT FROM POWER SUPPLY (Million $)					
SCENARIO	**LAO PDR**	**THAILAND**	**CAMBODIA**	**VIET NAM**	**TOTAL**
2015	5,026	10,423	253	7,515	23,217
2030	11,532	34,150	6,471	13,141	65,293

Note: GWh = gigawatt-hour

When the part of the project production is destined for another country, the gross annual export benefit is calculated at a proxy value for the actual trade price. This proxy is obtained as a discount over the replacement cost of power at the importing country and the discount is an input in page "SUMMARY" of the PEM Model. The result presented in Table 8.6 is only applicable to the host country.

Table 8.6: Results of Power Export Benefit Assessment

POWER EXPORT (GWh)					
SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	11,321	-	-	-	11,321
2030	64,792	-	9,528	-	74,320
BENEFIT FROM POWER EXPORT (in US$ million)					
SCENARIO	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	9,449	-	-	-	9,449
2030	31,816	-	2,585	-	34,401

The net annual economic benefit of the project is calculated differently for the host country and for the importing countries. For the host country, the net annual benefit is the sum of the benefit from power supply and from export less the annual cost of the project. For importing countries, the net annual benefit is the difference between the replacement value of imported power and the cost of import calculated at the proxy trade price. Table 8.7 presents the results.

Table 8.7: Results of Net Annual Economic Benefit Assessment

INVESTMENT (in US$ million)					
SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	2,933	-	102	3,227	6,262
2030	11,668	-	8,112	3,302	23,081
ECONOMIC BENEFIT (in US$ million)					
SCENARIO	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	11,302	1,563	122	3,467	16,454
2030	30,740	5,122	212	4,357	40,431

Table 8.8: Summary of Results

SCENARIO (year)	POWER SUPPLY (GWh)	POWER EXPORT (GWh)	CAPITAL INVESTMENT ($ million)	NET BENEFIT ($ million)	DISTRIBUTION OF NET BENEFITS (%)			
					LAO PDR	THAI	CAM	VN
2015	26,991	11,321	6,262	16,454	69	10	1	21
2030	110,898	74,320	23,081	40,431	76	13	1	11

Table 8.9: Summary of CO_2 Emission Reduction from Thermal Power Replacement

Estimated level of CO_2 emission from different types of thermal power pant					
Type of Thermal Plant	Estimation of emission (CO_2 tonnes/MWh)	Lao PDR	Thailand	Cambodia	Viet Nam
		0.84	0.71	0.84	0.92
Coal-fired steam plant	0.920	50%	60%	50%	100%
Oil-fired steam plant	0.755	50%	0%	50%	0%
Gas-fired combined cycle	0.404	0%	40%	0%	0%

Reduction of CO_2 Emissions (thermal power plant replacement by hydropower)

- LMB projects in operation by 2015: 22.36 million tons/year
- LMB projects in operation by 2030: 88.50 million tons/year

CO_2 Emissions from Hydropower Reservoirs

- LMB projects in operation by 2015: 1.49 million tons/year
- LMB projects in operation by 2030: 6.05 million tons/year

Net CO_2 Emissions Reduction from Hydropower Development

- LMB projects in operation by 2015: 20.87 million tons/year
- LMB projects in operation by 2030: 82.45 million tons/year

Key Challenges and Lessons Learned

- Political issues and unrest, including territorial disputes; and ensuring the ongoing cooperation, cost sharing, and coordinated decision making in the operation of regional market.
- Coordination issue, including conflicts between national and regional energy investment strategies.
- Investment issues, including the enormous financing requirements for expanding cooperation, such as developing generation assets, regional transmission network, institutional and policy frameworks, and the high risk perception by potential investors and developers (particularly in GMS members whose legal and political systems make protection of investment less certain) and the inability of the public sector to support these investments.

- Technical challenges of interconnecting disparate power system and ensuring security including communications, metering, and allocation of responsibility throughout a regional grid.
- Valuation issues arising from undeveloped power market in GMS members creating uncertainty in the determination of energy cost, tariffs, and price.
- Social issues, such as opposition to large hydropower projects and disputes over whether the regionalization of the GMS energy sector will actually enhance sustainable development or reduce poverty in light of concern that the benefit might be captured by a select group within certain GMS members.
- The Lao PDR hydropower industry's successful experience can be applied regionally in raising financing and attracting strong and credit-worthy off-takers. EGAT paved the way for the eventual structuring of a domestic supply project in the Lao PDR. Even today, only EGAT projects are able to move forward on a pure, project-financed basis with commercial lenders, as a result of the time-tested reputation of EGAT in its cross-border power ventures.
- In the case of Myanmar, a similar model is possible as its power exporting industry is at the same stage as that which the Lao PDR began building 20 years ago.
- The key role played by IFIs in fostering the necessary legal and legislative framework for commercial lenders to enter into an emerging economy's energy export market is worth looking into. The involvement of IFIs contributed to improving the financial and legal systems, political risk guarantee, and to providing the lender with enough assurance to feel comfortable in placing a financial stake in hydropower investment.

Conclusion

From the research, it is clear that power trade through power grid interconnection in GMS countries will result in significant benefits for individual countries and for the region. Among the benefits are as follows:

- Reduce dependency in national investment and provide alternative capital to invest in the power reserves to meet peak demand.

- Provide more reliable and alternative supply of electricity from interconnection network in case of power failure or shortage.
- Reduce operation costs and greenhouse gas emissions and other pollutants.
- Provide more economical source of energy, contributing to improved ability to access electricity.
- Contribute to national budget and economy with more tax revenues from the sale of electricity and from wheeling charge a (i.e., use of transmission charges).

However, hydropower could play an increasingly important role in the EMI of the GMS in the near future, serving as the answer to the rapidly growing demand for energy in the GMS countries while providing an alternative to dependency on fossil fuel. Considering the magnitude of the hydropower generating potential of the Mekong region, significant revenue benefits can be expected from electricity export.

Today, the existing power interconnections in GMS serve either to transmit electricity generated from export-oriented power plants or to dispatch power to cross-border areas experiencing domestic supply deficiencies and to areas distant from national networks.

Significant progress has been made in the GMS regional power trade since the beginning of GMS regional energy cooperation through a two-pronged approach to develop the GMS power market —the policy and institutional frameworks for promoting power trade and physical interconnections to facilitate cross-border power. However, to move toward a GMS power market, more efforts should be made by the GMS members themselves to realize the full benefits of synchronous operations in the GMS.

Recommendations

- For better assessment of hydropower generation potential, the main mechanism for power exchange in the GMS will be based on large-scale hydropower generation export. To attract more investors and reduce risk in hydropower investments, there is a need to refine investment cost, acquire hydrological data, and mitigate social and environmental impacts of these hydropower export projects to make them more sustainable.

- Promote inter-government joint investments in hydropower development and in power trading, and enhance the participation of the private sector and IFIs to accelerate the pace of development toward EMI.
- GMS members need to provide support to the Regional Power Trade Coordination Center's activities and role to reach a clear basis for regional market rules. These rules should comprise agreed rules and agreed indicative plans for interconnection (regional master integration planning) for a more functional regional market with genuine exchange of electricity, leading to greater supply reliability, improved quality of power supply, and lower costs. The Regional Master Plan needs to be reviewed and adapted regularly.
- A consistent update of the Power Development Plan and Transmission Expansion Plan among the GMS individual countries is needed to fit them into the regional master plan or to make the regional master plan regularly adapted.
- The GMS members need to support the Regional Investment Framework (RIF) of the energy sector and to prepare for its implementation.

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Annex-1
Methodology

Conceptual Aspects for Replacement Cost of Power Calculation

The economic evaluation of hydropower projects involves the calculation of the least cost of power generation that would be an alternative to hydropower. The least-cost alternative is a thermal plant using fossil fuel because, in general terms, including equivalent power reliability considerations, all other generation technologies for renewable resources are more expensive than hydropower generation. There are many thermal generation technologies in use today and the choice depends on the availability and price of fuels and the scale of the power systems to be supplied.

Expected Generation Expansion

The power generation structure of the Lao PDR will not change and will continue to be predominately hydropower. The only reason for the Lao PDR to use any other generation technology but hydropower is the cost of expanding and maintaining the transmission grid to reach every load.

Thailand will move toward reducing its dependency on gas and coal with as much hydropower as it can competitively import. Natural gas is a fuel that can be used advantageously in several sectors including industrial heat, residential cooking, and transport and, therefore, its use for power generation may not be the most efficient from an overall national energy planning perspective.

Cambodia’s power sector is expected to change radically from its current, almost complete, oil dependency to a mix of hydropower and coal.

Viet Nam has ambitious plans for new coal and nuclear capacity by 2020 but that capacity and the expected capacity of new domestic hydropower still leaves a large gap against expected demand. That gap will likely be filled by imports of hydropower energy from the Lao PDR, more aggressive coal or nuclear development, or more likely, a combination of all these three.

The energy supply sources for Yunnan and Guangxi provinces of China are mainly hydropower dominated but mixed with coal. The future expansion will remain unchanged due to the huge potential of hydropower and coal resources in Yunnan with some plans to initiate nuclear generation in Guangxi.

Myanmar's energy supply relied heavily on seasonal hydropower generation, followed by gas, with a few portion of coal, but lacks domestic gas supply and capacity for gas-fired power generation to maintain the stability of the supply system. For the future, generation expansion plans will mainly focus on hydropower and gas-fired power generation, with some options for coal-fired power generation.

Viable Thermal Alternatives

Thermal generation alternatives are a combination of fuel and generation technology. Not all the technologies can burn all fuel and, generally, the most expensive technologies to build can burn cheaper fuel and vice versa.

Coal is the cheapest fossil fuel but can only be burned in steam plants, which are expensive to build.

Natural gas can also be burned in steam plants but it is cheaper and more efficient to use in a technology called "combined cycle" that consist of a combination turbine (similar to jet engine used in aircraft) and steam turbines. Steam turbine and combined cycle technologies are capable of large- scale generation with capacities of up to several thousand megawatts (MW) per plant.

Two oil products are of common use in smaller-scale power generation. **Distillate fuel oil**, also known as "diesel oil", is very expensive compared to natural gas or coal but can be used in low-cost diesel engines that are only practical with a capacity of just a fraction of one MW. These engines are relatively light machines, similar to diesel engines used in trucks and are known as "high-speed diesel". **Residual oil**, also known as "bunker oil", has a lower cost compared to that of crude oil and can be used in heavier diesel engines with capacity of up to 30 MW. These engines are also used in ships

and are known as “low-speed diesel”. The cost is comparable to that of combined cycle machines.
Nuclear power is, of course, a viable technology for the scale of the system of Thailand and Viet Nam but its use as thermal reference for hydroelectric project evaluation is not practical because the full extent of nuclear generation cost, including fuel disposal and plant decommissioning, is very complex to evaluate.

In summary, in the absence of hydropower and nuclear power, a large system would lean toward combined cycle technology if natural gas and steam technology were available, using domestic or imported coal if gas is not available. A small system would start with high-speed diesel for very small isolated loads, moving to low-speed diesel as more loads become interconnected and, finally, would start moving into combined cycle or steam turbine technologies depending on the availability of natural gas.

Fuel Costs

Fuel prices have been volatile in the past few years and this volatility complicates the use of any specific value. Current price for oil products can be derived by using the cost of crude for bunker and approximately 50% above the cost of crude for diesel. Current cost of natural gas prices can be estimated based on recent transactions in Viet Nam and Thailand.

However, energy observers agree that it is highly probable that fuel prices, will, over the foreseeable future, increase at a higher rate than the general inflation that is expected. This increase in price above the general level of inflation is called escalation. In particular, fuels that are of practical use in the transportation sector, such as oil or natural gas, are likely to experience the highest price escalation. For this reason, current prices are not appropriate to be used in an analysis based on real terms since they could not be converted into nominal prices by merely applying inflation.

The value used for current fuel prices and for the assumed fuel price escalation are variable in the “SUMMARY” page of the Power Evaluation Model, PEM. These values and the resulting “levelised” fuel prices are shown in Table 8.A1.

Table 8.A1: Current and "Levelised" Fuel Prices

Fuel Type	**Diesel**	**Natural Gas**	**Bunker**	**Coal**
Fuel Price Trade Unit	**US$/bbl**	**US$/TCM**	**US$/bbl**	**US$/ton**
Reference heat content per trade unit in Mbtu	5.54	36.27	5.81	22.00
2010 fuel price in US$/Mbtu	22.60	14.00	12.00	4.00
2010 fuel price in US$/trade unit	125.1	507.8	69.8	88.0
Mean annual escalation rate of fuel prices (Sensitivity)	0%	0%	0%	0%
Current fuel price "levelised" value	**125.0**	**507.8**	**69.8**	**88.0**

Notes:

Bbl = American barrel = 42 American gallons = 158.97 liters
TCM = thousand cubics metres = 35,314.7 cubic feet
Ton = metric ton = 1,000 kilograms = 2,204.6 pounds
Mbtu = million British thermal units = 251,996 kilocalories

Source: Power Evaluation Model, 2013

To account for the real future cost of replacement power, the current price had been escalated over the next 20 years, at the expected rate of increase in price over general inflation. The resulting annual prices are then "levelised" for the 20-year period using the economic discount rate. The "levelised" value is such that the present 2010 value of a string of constant annual "levelised" values is the same as the present value of the specific annual escalated values.

Variable Cost of Replacement Power

The cost of fuel is the primary component of the variable cost of power from thermal plant. This component is obtained by combining the cost of the fuel with assumption on the heat content of each fuel and the thermal efficiency or "heat rate" of each generation technology. Other components of the variable cost are then added as a percent of the fuel cost to account for lubricants and other consumables. The calculation of variable cost for the four alternatives considered is shown in Table 8.A2. The variable cost is also known as the "Energy" cost of power. "Power" is a term that, in the electricity generation industry, includes both energy and capacity components.

Table 8.A2: Variable Cost of Replacement Power

Fuel type		Distillate Oil No. 2	Natural Gas	Residual Oil No. 6	Anthracite Coal
Usual trade unit	Unit	Barrel	Thousand Cubic Metres	Barrel	Metric Ton
Heat content per trade unit	Mbtu/unit	5.54	36.27	5.81	22.00
Cost per trade unit	US$/unit	125.00	507.76	70.00	88.00
Unit fuel cost	US$/Mbtu	22.58	14.00	12.04	4.00
Heat rate	btu/kwh	12,000	6,800	8,500	9,125
Variable cost fuel	US$/MWh	270.97	95.20	102.36	36.50
Variable operation and maintenance	% of fuel cost	5.50%	10.50%	9.80%	8.22%
Variable operation and maintenance	US$/MWh	14.90	10.00	10.03	3.00
Total variable cost	US$/MWh	285.88	105.20	112.39	39.50

Source: Power Evaluation Model 2013

Investment: The sum of the engineering, procurement, and construction (EPC) and the interest during construction (IDC) results in the present value of the investment at the time of commissioning the project.

Fixed Cost of Replacement Power: This is the fixed cost of power in the plant's annual cost of operating expense and the cost of amortizing the investment on the plant.

Unit Annual Fixed Cost: This is the sum of the annual capital and operating cost divided by the installed capacity of the plant. Table 8.A3 shows the calculation of unit fixed costs for the generation alternatives under consideration.

Table 8.A3: Calculation Unit Fixed Cost of Replacement Power

Reference Generation Technology	Unit	High-Speed Diesel	Combined Cycle	Low-Speed Diesel	Coal Fired Steam Turbine
Fixed cost calculation					
Unit EPC	US$/kW	400	800	1,000	1,600
Construction period	Years	1	2	2	5
Unit IDC	US$/kW	20	80	100	400
Unit capital cost	US$/kW	420	880	1,100	2,000
Economic life	Years	15	25	15	30
Capital recovery factor		0.131	0.11	0.131	0.106
Unit annual capital cost	US$/kW	55.22	96.95	144.62	212.16
Fixed operation and maintenance cost	% of EPC per year	3.00%	3.00%	3.00%	3.00%
Unit fixed operation and maintenance cost	US$/kW	12	24	30	48
Unit annual fixed cost	US$/kW	67.22	120.95	174.62	260.16

EPC = engineering, procurement, and construction, IDC = interest during construction, K= kilowatt
Data source: Power Evaluation Model Result, 2013

Capital Costs

Unit EPC Cost: This is the estimated cost of engineering procurement and construction involved in building the plant. The Unit EPC is obtained by dividing the EPC cost by the installed capacity of the plant.

IDC Cost: The interest during construction represents the opportunity cost of capital disbursed during construction up to the time when the project starts operating. This cost is a function of the duration of construction, of the discount rate, and also of the schedule of disbursement during construction. To simplify the analysis, it is assumed that IDC can be approximated by using the following formula:

$$IDC = 0.5 * EPC * P * i$$

Where:

IDC = is the interest rate during construction
EPC = is the EPC in million US$
i = is the discount rate
P = is the construction period in years

Annual Capital Costs

The annual amortization of the investment over its economic life *L* is a value, such that the accumulated present value of the string of *L* constant values is equal to the investment. This annual amortization is obtained by multiplying the investment by the Capital Recovery Factor (CRF). The CRF is given by the following formula:

$$CRF = [(1+i)^{L} * i] / [(1+i)^{L}-1]$$

Where:
CRF = Capital Recovery Factor
i = discount rate
L = economic life in years

Then [**Annual Capital Cost = Investment * CRF]**

The annual capital cost is an economic and cost accounting concept that does not represent a real annual disbursement. However, the CRF can also be used to calculate the annual cost of debt services on a loan used to finance the plant. This can be done by making the following replacement:

a) Replace “investment” by “Loan Amount”
b) Replace “Economic life” by “Loan Term”
c) Replace “Discount Rate” by “Loan Interest”

Monomic Cost of Replacement Power

Generation projects contribute two types of services to an electric power system. One service is “energy supply” and the value of this service is captured by the variable cost of replacement power discussed above and commonly measured in $/MWh. The other service is “Capacity Supply”, which represents the contribution to the system’s ability to meet peak demand. The value of this service is captured by the fixed cost of replacement power discussed above and commonly measured in $/MW-year. It is often more practical in economic analysis to use a single value that captures both energy and capacity component of value. This is called the “monomic (or one-part) value” and it is obtained through the following formula:

$$M = [(E*8760*LF) + C]/(8760*LF)$$

Where:

M = Monomic value
E = Energy value
LF = Load factor
8760 = number of hours per year

This formula essentially spreads the fixed cost of one megawatt of capacity (required to meet peak demand) over the expected megawatt-hours of energy demand that are expected to be associated with that during one year.

Such association of energy of capacity is captured by the “Load Factor” and is typically between 0.60 and 0.80 for most power systems. The value 0.70 was used in this approximation. Table 8.A4 shows the calculation of monomic value of the alternative under consideration for a range of load factor of the power system under analysis.

Table 8.A4: Monomic Replacement Cost of Power

Capacity Value	**US$/kW-year**	**67.22**	**120.95**	**174.62**	**260.16**
Energy Value	**US$/MWh**	**285.88**	**105.2**	**112.39**	**39.5**
	Load Factor (%)				
Monomic value in US$/MWh as a function of capacity factor	10	362.6	243.3	311.7	336.5
	20	324.2	174.2	212.1	188
	30	311.5	151.2	178.8	138.5
	40	305.1	139.7	162.2	113.7
	50	301.2	132.8	152.3	98.9
	60	298.7	128.2	145.6	89
	70	**296.8**	**124.9**	**140.9**	**81.9**
	80	295.5	122.5	137.3	76.6

Source: Power Evaluation Model, 2013

Replacement Cost by Country

Once the monomic cost of power for each thermal generation option has been determined, there is a need to estimate what will be the proportion of each option that would be used in each country if hydropower were not available. Some clues can be obtained from the expected generation expansion plans. This will be explained below as the results are shown in Table 8.A5.

Table 8.A5: Power Replacement Cost, by Country

Generation Technology	Cost	Percentage Use of Generation Technology (%)			
	US$/MWh	LAO PDR	THAILAND	CAMBODIA	VIET NAM
High- or medium-speed diesel units using diesel oil	**296.8**	**30**	**9**	**30**	**0**
Low-speed diesel units using bunker oil	**140.9**	**20**	**1.0**	**30**	**0**
Combined cycle units using natural gas	**124.9**	**0**	**82**	**0**	**0**
Steam turbine units using coal	**81.9**	**50**	**8**	**40**	**100.0**
Monomic replacement cost of power (US$/MWh) at 70% system load factor		158.2	137.1	164.1	81.9

Source: Power Evaluation Model, 2013

The clearest case is Viet Nam. It seems reasonable to expect that, if nuclear or hydropower were not viable options, then Viet Nam would pursue a fully coal-fired power generation expansion and the replacement cost of that power, accounting for all costs including escalation of coal prices, is US$**81.9/MWh (or 8.2 cents/kWh)**.

Thailand is a little more complex because it is unclear how much of future demand can actually be covered by natural gas, which probably would be the preferred option since it is both cleaner and cheaper power. It has been assumed that in the absence of hydropower, 82% of the incremental demand would be covered by combined cycle machines using natural gas and the rest with coal-fired stream plants and oil-fired stream plants. This will result in a replacement cost of power of US$**137.1/MWh (or 13.7 cents/kWh)**.

Cambodia currently relies almost entirely on oil-fired power generation and reports a plan for coal-fired power generation. Coal would, therefore, appear like a reasonable alternative but its current reliance on small diesel generators makes it unlikely that the transmission system would be capable of immediately providing coal-fired power everywhere. Thus, a balanced mix of coal-fired system and high-speed diesel has been assumed as a reasonable option over the next 20 years if hydropower was not available. This will result in a replacement cost of power of US$**164.1/MWh (or 16.4 cents/kWh)**.

The Lao PDR is the most difficult case to assess since there are no plans or expectations for thermal power supply. However, the country has a reasonable transmission and, thus, it could be expected that, in the absence of hydro, much of the load could be supplied with coal-fired power generation or at least, low-speed diesel generator and only isolated parts would still rely on high-speed diesel. A reasonable combination of these thermal generation options would result in a replacement cost of power of US$**158.2/MWh (or 15.8 cents/kWh)**.

METHODOLOGY FOR CO_2 EMISSION REDUCTION CALCULATION

Hydropower projects will avoid the emission of carbon dioxide (CO_2) that would result from fossil fuel-fired power generation. In addition, the project would also mitigate other pollutants, such as sulphur oxide (SO_2), nitrate oxide (NO_x), and particulates associated with power generation from fossil fuels. Thus, the hydropower project will contribute to the reduction of CO_2 emission from existing and future thermal power plants using diesel generator, coal, and natural gas. The amount of reduction of CO_2 by the hydropower (Y) can be calculated using the following formula;

Y = CO_2 emission from thermal power plants – CO_2 emission by hydropower projects + disappearance of CO_2 absorption resulting from deforestation + CO_2 emission from reservoir

Since hydropower is a clean energy source, there will be no CO_2 emissions that are directly related to hydropower generation.

CO_2 Emissions from the Thermal Power Plant

CO_2 from diesel generator per kWh is calculated with the following formula (Nippon Koei Co. Ltd., 2007).

$$Z = \frac{Eh \times SFCh \times RDh \times EFh \times HVh + Ed \times SFCd \times RDd \times EFd \times HVd}{Eh + Ed}$$

Where:

Z = emission from diesel generator per kWh generation

h = heavy fuel oil or heavy fuel oil-fired generating units

d = light diesel oil or light diesel oil-fired generating units

E = energy production (LDO-fired diesel unit: 219.8 GWh/year, HFO-fired diesel unit: 587.3 GWh/year)

Source: Electricité du Cambodge (2005), *Statistical Handbook, 2005, by Cambodian State Own Power Utility Company (EDC),* Phnom Penh, Cambodia

RD = relative density (LDO = 0.876, HFO = 0.900)

SFC = specific fuel consumption (LDO-fired diesel unit: 0.285 liter/kWh, HFO-fired diesel unit: 0.233 liter/kWh

Source: Electricité du Cambodge (2005), *Statistical Handbook, 2005, by Cambodian State Own Power Utility Company (EDC),* Phnom Penh, Cambodia

EF = emission factor (LDO = 0.0741 kg-CO_2/GJ, HFO = 0.0770 kg-CO_2/GJ)

Source: CDM Executive Board, June 2006.

HV: heat value of fuel (LDO = 48.61 GJ/ton, HFO = 43.39 GJ/ton)

Source: US Department Of Energy (DOE) /Energy Information Administrative (EIA) (2005), *Annual Energy Outlook, 2005*, USA.

As a result, it was estimated that CO_2 emission from diesel generator is **0.755 ton/MWh**

From the International Energy Agency (IEA) (2012), the CO_2 emission from coal power plant is **0.920 ton/MWh.**

The CO_2 emission from combined cycle gas turbine (CCGT) using natural gas is **0.404 ton/MWh**

As result from the CO_2 emission reduction due to the replacement of thermal power plant by hydropower development in the Lower Mekong River Basin the following scenario is presented:

Emission Reduction of CO_2 in Million Tons/Year

SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	3.57	4.90	0.17	11.33	**19.97**
2030	12.58	26.65	8.31	27.86	**75.40**

Source: MRC (2014)

<u>Disappearance of CO_2 Absorption by Deforestation</u>

The hydropower project included the construction of dam to create a head for power generation and to control the flow of water and, therefore, certain areas of the land will be submerged under the reservoir. Thus, after the implementation, certain areas of forest land will be submerged. In this analysis, the tropical forest's annual absorption of CO_2 was estimated based on the following formula and data quoted from the IPCC guidelines for National Green House Gas inventories in 2006.

$$\text{Annual } CO_2 \text{ Absorption (ton-}CO_2\text{/ha)} = (AGBG \times (1+R) \times CF \times MW_{CO2})/MW_c$$

Where:

AGBG: Above ground biomass growth (2.2 ton dry matter (dm.)/ha/year, tropical rain forest in Asia continent)
R: Ratio of below-ground biomass (0.37 ton rood dry matter (d.m.)/ton shoot dry matter (d.m.), tropical rainforest)
CF: Carbon fraction (0.47 ton-C/ton d.m., tropical and subtropical, all parts of a tree)
MW: Molecular weight (CO_2 = 44, C = 12)

Annual CO_2 absorption of tropical forest in Mekong was estimated at 5.19 ton-CO_2/ha/year.

Due to unavailability of data for forest areas submerged by reservoir impoundment of hydropower projects, the CO_2 absorption of forest was neglected in the net CO_2 emission calculation.

CO_2 Emission from the Reservoirs

CO_2 emission from reservoir results from the decomposition of leaves, twigs, and other rapidly degradable biomass. Slowly decaying woody biomass, organic matters washed into the reservoir from upstream, and the growth of biomass in the reservoir provide long-term source of CO_2 and methane production. Reservoir emission lasts for many decades at least and presumable for the life of the reservoir. According to the "thresholds and criteria for the eligibility of hydroelectricity power plant with reservoirs as CDM projects activities" of the Clean Development Mechanism Executive Board, the emission of CO_2 from the reservoir is defined as follows, based on threshold in terms of power density (installed power generation capacity divided by the flooded surface area Watt per square meter (W/m^2); (UNFCCC-2006); (CDM-EB23, Report Annex 5):

i. Hydropower plant with power densities less than or equal to 4 W/m^2 cannot use current methodologies.
ii. Hydropower plant with power densities greater than 4 W/m^2 but less than or equal to 10 W/m^2 can use current approved methodologies with emission factor of 90 g-CO_2/kWh for project reservoir emission.
iii. Hydropower plant with power densities greater than 10 W/m^2 can use current approved methodologies and the project emission from reservoir may be neglected.

With reference to these criteria, CO_2 emission from a reservoir was calculated at 90 g-CO_2/kWh with a power density less than 10 W/m^2 and zero with power density greater than 10 W/m^2.

Below is the amount of CO_2 emission from hydropower reservoirs in the Lower Mekong River Basin and net calculation of CO_2 emission reduction from hydropower development.

SCENARIO (year)	CO_2 Emission from Hydropower Reservoirs	Net CO_2 Emission Reduction from Hydropower Development
2015	1.49 (million ton/year of CO_2)	18.48 (million ton/year of CO_2)
2030	6.05 (million ton/year of CO_2)	69.35 (million ton/year of CO_2)

CHAPTER 9

Deregulation, Competition, and Market Integration in China's Electricity Sector

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This report presents an updated and expanded review of reforms in China's electricity sector. It aims to examine the impact of reforms on competition, deregulation, and electricity market integration in China. The findings are used to draw policy implications for electricity market development, particularly the promotion of energy market integration (EMI).

Keywords: electricity sector, reforms, unbundling, energy market integration and China

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Introduction

East Asia Summit (EAS) members have been actively promoting energy market integration (EMI) in their individual economies as well as within the EAS block. Among various energy products, electricity plays an important role in EMI as it allows member-countries to be connected through cross-border power grids. China as an EAS member has been the world's largest electricity user as well as producer since 2011. The country has also been engaged in cross-border trading in electricity with several other EAS members (namely, Lao PDR, Myanmar, and Viet Nam). Internally, China's electricity sector has undergone dramatic changes, and further restructuring is anticipated in the near future. Thus, a study of China's electricity sector may help elicit important insights into issues such as deregulation, competition, and market integration. The findings may also have implications for other EAS member economies that are undertaking a similar trajectory of reforms.

Several existing studies have focused on China's electricity sector. For example, the role of the private sector in China's power generation was the theme of a World Bank (2000) conference. Also, an Asian Development Bank (ADB) report examined electricity demand and investment requirements (Lin 2003). Several years later, a study by the International Energy Agency or IEA (2006) discussed further reforms after the 2002 restructuring and provided policy recommendations for the Chinese government, while Yang (2006) presented a brief review of China's electricity sector.

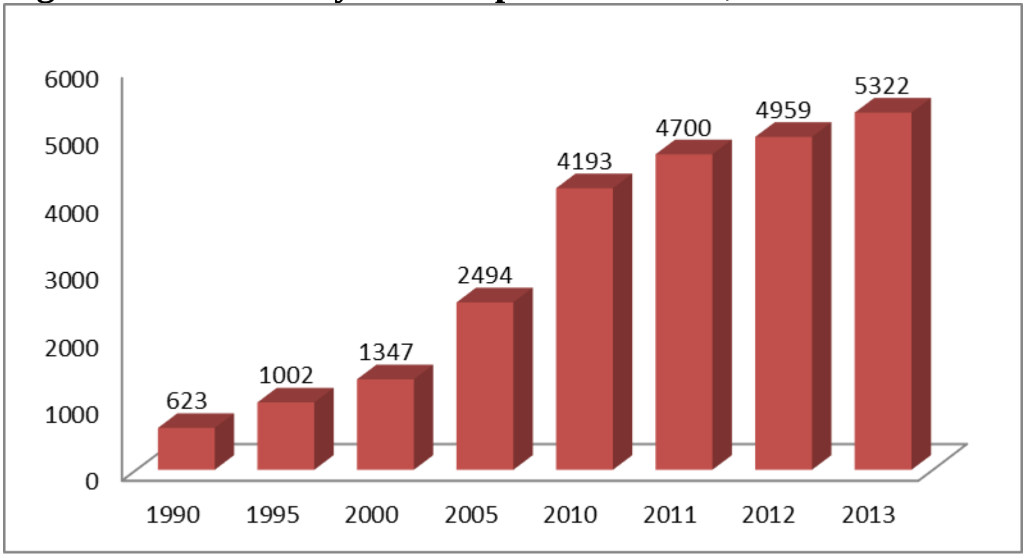
More recently, a short report by ADB (2011) provided observations and suggestions about China's electricity sector; an IEA (2012) project explored the policy options for low-carbon power generation in China; and an ERIA discussion paper (Sun *et al*., 2012) examined barriers to private and foreign investment in China's power sector. However, these existing research works are either outdated or concerned with a specific issue. Thus, this study aims to present an updated examination of various issues in China's power sector, especially on reforms and market integration. It begins with a review of China's electricity industry, followed by a discussion of major reforms in the sector. The challenges and implications are then explored. The paper concludes with some policy recommendations.

China’s Electricity Sector

Demand for electricity has seen robust growth for decades in China (Figure 9.1). In particular, it doubled between the years 1990 and 2000 and trebled between 2000 and 2010. In 2011, China overtook the United States as the world’s largest power consumer with a consumption share of 21.8 percent of the world's total, while the US share continuously declined to 20.3 percent (Figure 9.2). Power demand in China is now more than the combined total consumption in Japan, Russia, India, Germany, Canada, and Brazil. However, on a per-capita basis, China’s power consumption is only a fraction of that in major economies such as the United States and Japan (Figure 9.3).

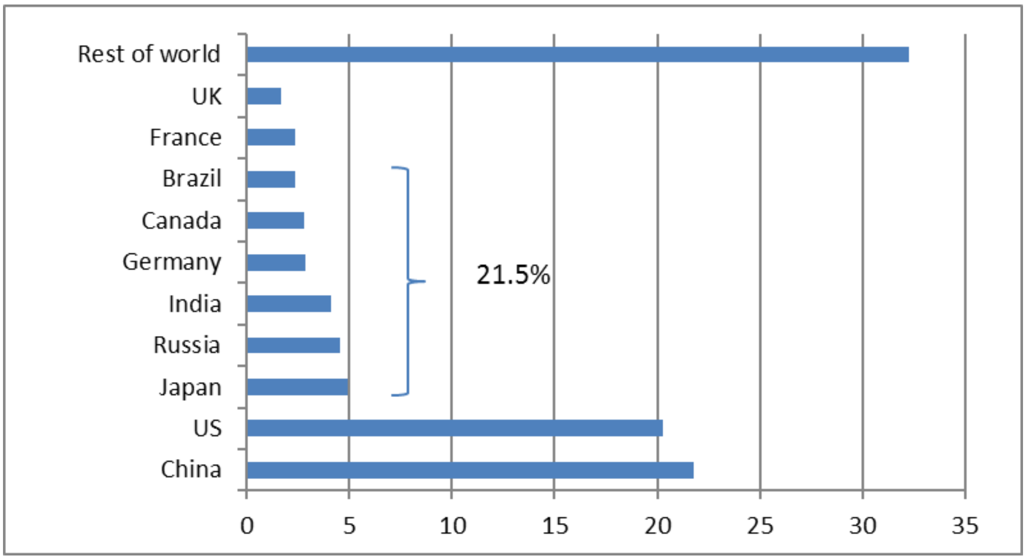
While the Chinese economy flourishes, there remains considerable room for further growth in both per-capita and total electricity consumption. For example, electricity demand in China will reach 8,767 terawatt hours (TWh) in 2035, according to the ADB (2013). That level would double China’s total consumption in 2010. In terms of per-capita consumption, China would only proximate the current level of demand in Russia or Japan. According to J. Wu (2013), China’s per-capita consumption of electricity in 2050 will reach 9,300 kilowatt hours (KWh), which is close to the current consumption level in high-income OECD economies in 2011 (WDI, 2013).

Figure 9.1: Electricity Consumption in China, 1990-2013



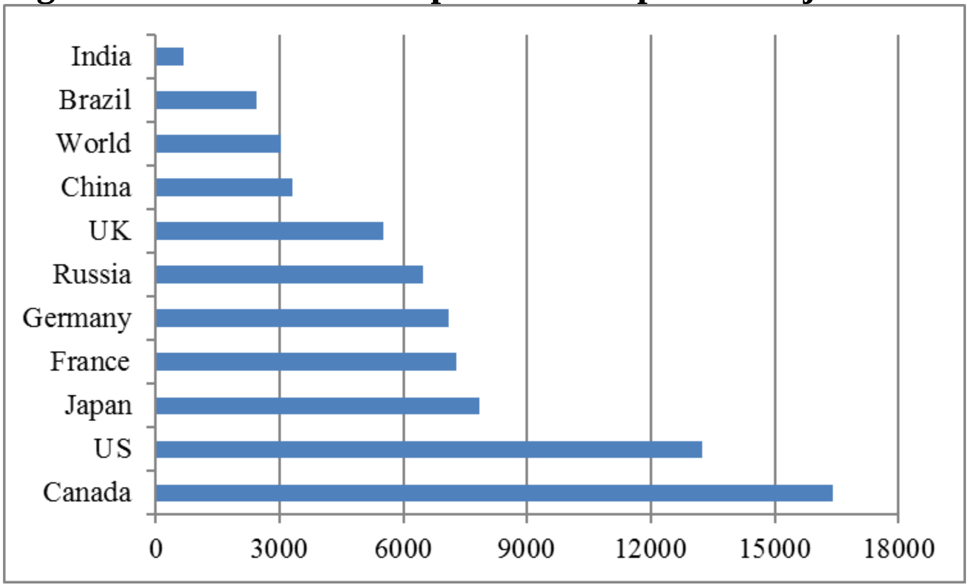
Note: The unit on the y-axis is TWh.
Source: NBS (various issues) and NEA (2014).

Figure 9.2: Consumption Shares (%) in Major Economies in 2011



Source: The numbers are calculated using data from WDI (2013).

Figure 9.3: Power Consumption Per-Capita in Major Economies in 2011



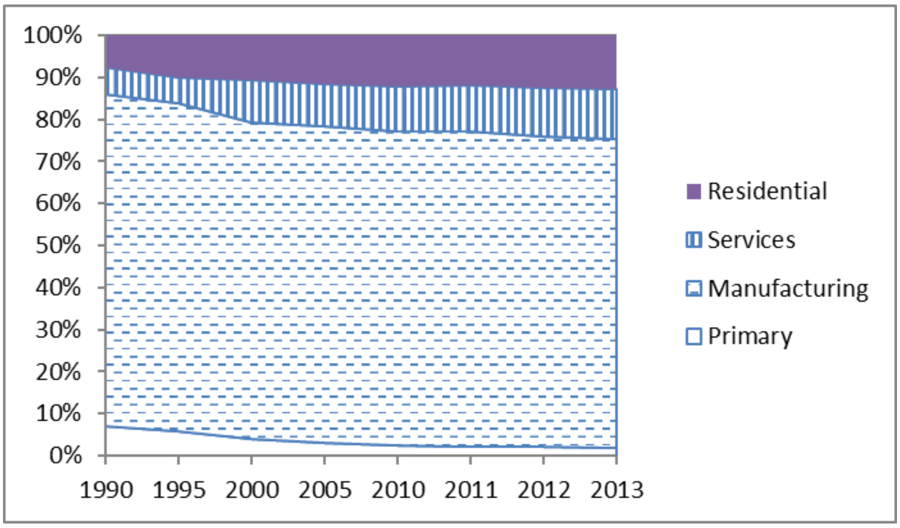
Note: The unit of measurement is kilowatt hours (kWh).
Source: WDI (2013).

At the sector level, manufacturing still accounts for the lion's share of China's total electricity consumption due to the ongoing rapid industrialisation (Figure 9.4). In 2013, the manufacturing sector used 73.5 percent of China's total electricity consumption, which is slightly smaller than its 79.3 percent share in 1990. Therefore, while manufacturing's share of China's electricity consumption is still high, it is declining. In comparison, the Japanese manufacturing sector's share dropped from 70.2 percent in 1973 to 29.7 percent by 2011. Likewise, that of South Korea slid from 69.0 percent in 1973 to 52.3 percent by 2011 (OECD, 2014). If these are any indications of China's own trajectory, then the country's manufacturing's share of electricity consumption is expected to also continue to fall in the coming decade.

However, power consumption in the service and household sectors grow faster than that in the primary and manufacturing sectors. For example, the average percentage growth rates during 2005-2013 are 3.4 percent for the primary; 9.6 percent, industrial; 12.1 percent, service; and 11.3 percent, residential sector. As a result, consumption shares of households and services increased from 7.7 percent and 6.2 percent in 1990, to 12.8 percent and 11.8 percent in 2013, respectively. During the period 1973-2011, these shares respectively rose from 19.1 percent and 10.5 percent, to 30.9 percent and 38.8

percent in Japan; and from 12.1 percent and 18.3 percent, to 13.1 percent and 32.3 percent in South Korea (OECD, 2014). There is, hence, considerable room for growth in the electricity consumption of China's own household and service sectors.

Figure 9.4: China's Electricity Consumption Shares By Sector, 1990-2013

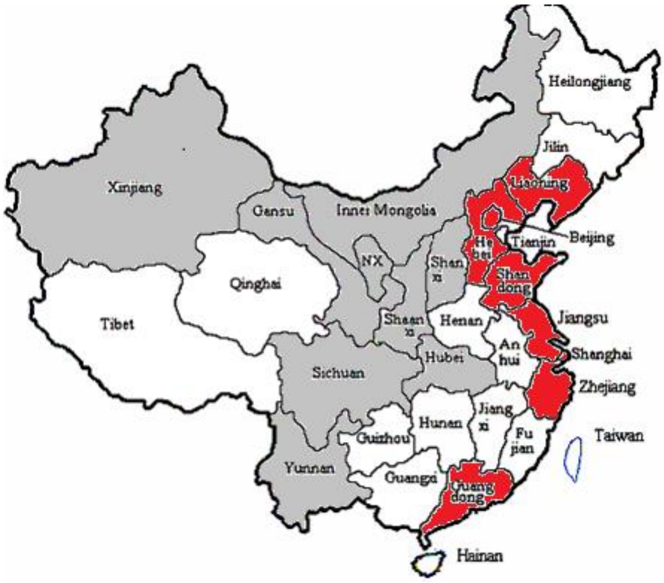


Source: Author's own estimates using data from the NBS (various issues) and NEA (2014).

One of the features in China's electricity sector is the uneven distribution of resources across its regions. In particular, the coastal regions tend to be net importers of electricity while the western regions are net exporters (Figure 9.5). Thus, cross-regional electricity trade in China is inevitable. This requires efficient transmission lines and an integrated market. For example, Xinjiang's power grid was connected with the northwest power grid in 2010 and has since exported electricity to the rest of the country, including Jiangsu and Zhejiang (CP, 2013). In 2013, the total power exported from Xinjiang amounted to 6 TWh, according to Xinhua News Agency (2014a).

There is also some cross-border power trading between China's Yunan province and Lao PDR, Myanmar, and Viet Nam. The first cross-border transmission between China and Lao PDR took place in 2001; and that between China and Viet Nam in 2004. China reportedly exported 3.2 gigawatt hours (GWh) to Viet Nam and 0.2 GWh to Lao PDR in 2013. In the same year, Yunan also imported about 1.9 GWh from Myanmar (MOC, 2014). So far, the total power exchanges are valued at about US$1.5 billion. Heilongjiang in Northeast China has also been importing electricity from Russia amounting to about 13 GWh since 1992.[2] Imported Russian electricity is anticipated to reach 3.6 GWh in 2014.

Figure 9.5: Power Supply and Demand Situations By Region

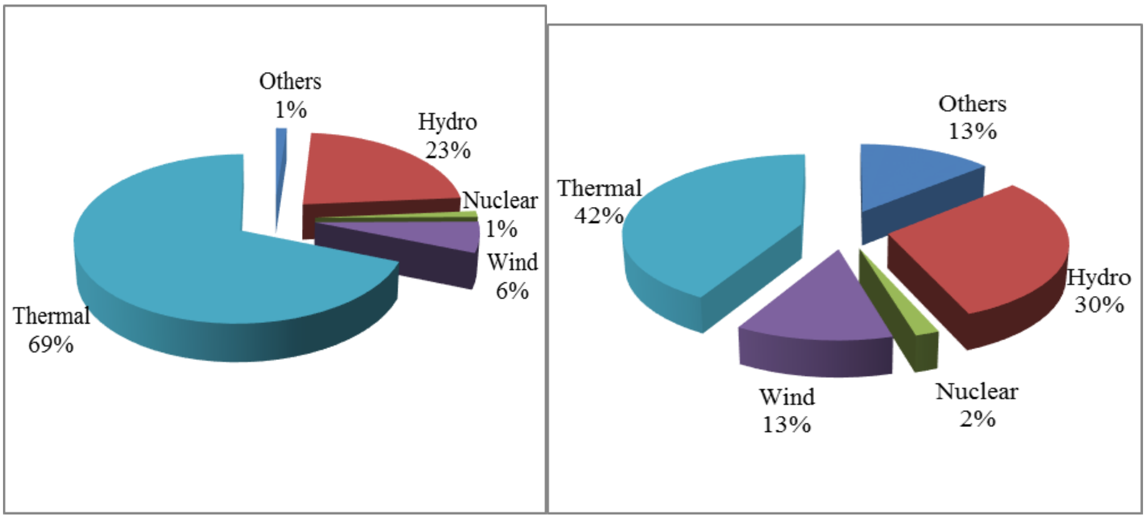


Note: Power exporting and importing regions are painted in black and red, respectively. Regions without colour have either small deficits or surplus in power supply.
Source: Author's own drawing.

By 2013, China's total installed generation capacity amounted to 1,247 gigawatts (GW), of which 862 terawatts (TW) are sourced from thermal, 280 TW from hydro, 75 TW from wind, and 15 TW from nuclear power plants (NEA, 2014). Clearly, thermal power facility takes the dominant share (Figure 9.6). According to a Bloomberg (2013) report, China's generation capacity will be more than double in 2030, with large expansions in wind and solar energy-powered generations. This changing trend is already taking place. Of the newly installed generation capacity in 2013, more than a half is based on non-thermal sources (Figure 9.6).

[2] These import statistics were reported by Xinhua News Agency (2014b).

Figure 9.6: Structure of China's Generation Capacity, 2013



(a) Total installed capacity (b) Newly installed capacity

Sources: NEA (2014).

The structure of production output is generally consistent with the pattern of generation capacity. Coal-fired generators still dominate thermal production and account for the largest share, followed by hydropower (Table 9.1). The market is divided between fossil fuel generation (coal, oil, and gas) with a share of 80.9 percent, and non-fossil fuel production with a share of 19.1 percent in 2011.

In the near future, coal will remain a main fuel in China. Coal-fire power is projected to still secure about 43 percent of the market share in China by 2050 (J. Wu 2013). This has serious environmental consequences. It also leaves China far behind its neighbours in terms of international environmental perspectives. For example, Germany will reportedly reduce its use of coal in electricity generation and increase the share of renewables from the current 25 percent to 80 percent in 2050 (The Economist, 2014). Meanwhile, in that same year, China's electricity production is projected to still be divided equally between fossil fuels and non-fossil fuels (J. Wu, 2013).

Table 9.1: China's Electricity Output Shares (%) in 2011

Fossil fuels	Shares	Non-fossil fuels	Shares
Coal	78.953	Nuclear	1.831
Gas	1.781	Hydro	14.822
Oil	0.168	Wind	1.491
		Solar	0.054
		Biofuels	0.668
		Waste	0.229
		Others	0.003
Sub-total	80.902	Sub-total	19.098

Source: IEA (2013)

Evolution of Reforms in the Power Sector

China's electricity sector began with a single vertically integrated utility, which the government through its Ministry of Power Industry owns and operates. Following the global trend of deregulation, a series of reform initiatives were implemented. The first reform initiative in China's power sector was the introduction of independent power producers (IPPs) into the generation sector in the 1980s (IEA, 2006). At one point, IPPs in China cornered a 14.5 percent market share (Sun, *et al.*, 2012). By the late 1990s, all non-state generators provided more than half of the country's total electricity supplies (Wu, 2013; Du, *et al.*, 2009).

The participation of IPPs and other non-state generators were argued to play a critical role in the growth of China's power generation. While fuel and equipment prices increased dramatically, competition helped reduce the cost of generation and boosted output growth to overcome investment inadequacy and power shortage in the country in the 1990s.

The second major change was the corporatisation of the electricity businesses, thus establishing the State Power Corporation (SPC) in 1997 (Sun, *et al.*, 2012). This represents the first move to separate businesses from regulatory activities. The SPC was state-owned and a typical vertically integrated power supplier. It later became the main focus of electricity sector reforms in China.

The third wave of reforms was initiated in 2002. China's ambitious program involved the unbundling of power distribution, grid management, and generation. The goal was to introduce competition into the electricity industry. Due to this round of reforms, the SPC was divided into two grid companies, five generation companies, and two auxiliary companies (i.e., the Power Construction Corporation of China and China Energy Engineering Group Co Ltd). The two grid companies are the State Grid Corporation (SGC), which owns five regional grids; and South China Grid Corporation (SCGC), which operates the grid that interconnects five southern regions (Figure 9.7). Meanwhile, the five power generation companies are China Huaneng Group, China Huadian Group, China Datang Co., China Guodian Co., and China Power Investment Co. (Shi, 2012). These five power providers together captured a market share of about 40 percent in 2006 (Zhang, 2008).

Figure 9.7: Map of China's Main Power Grids

Source: Author's own drawing.

In the area of institutional development, the promulgation of the Electricity Act in 1995 was a hallmark. The Act laid the foundation for reforms in 1997 and 2002. To strengthen regulatory functions, the State Electricity Regulatory Commission (SERC) was formed in 2003. Its role is to promote reforms and create a market-based power industry with competing players and to set prices according to supply and demand situations in the market. Following the formation of SERC, a series of regulatory rules were released in 2005, including the first major revision of the 1995 Electricity Act (Table 9.2). Those rules and the Act have since guided the supply and demand of electricity, grid access, infrastructure development, and energy preservation in China.

However, it is argued that after almost a decade, SERC as an independent regulatory body still falls behind its stated goals (Shi, 2012). For example, open bidding for grid access was pilot-tested in two regional markets (Northeast and East China) but was later suspended. Government also still plays the key role in price setting. In 2013, SERC and National Energy Administration (NEA) merged to form the current NEA.

Table 9.2: China's Electricity Sector Reform Initiatives

Periods	Reform initiatives
1979	Establishment of the Ministry of Power Industry
1980s	Introduction of IPPs
1995	Release of the Electricity Act
1997	Establishment of SPC
2002	Split of SPC into SG and SCG
2003	Formation of SERC
2005	Revision of the Electricity Act
2008	Formation of NEA
2010	Establishment of NEC
2013	Merger of SERC and NEA
2014	Pilot reforms in Yunnan and Inner Mongolia

Source: Author's own work.

In March 2014, right after the National People's Congress (NPC) and Political Consultative Conference (PCC), reforms in the electricity sector gained new momentum. During the two political gatherings, a consensus was reached to deepen economic reforms, including those in the power sector.

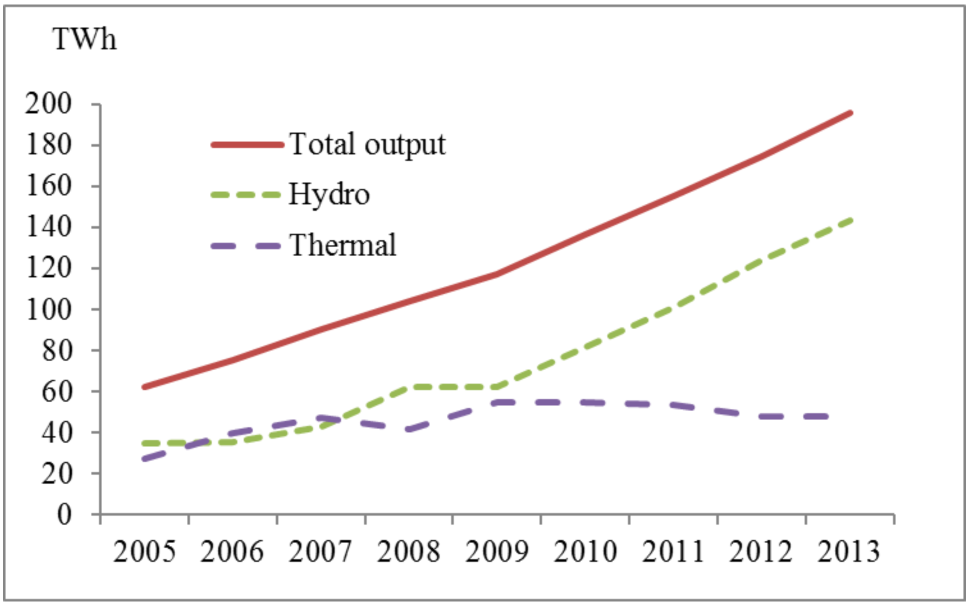
On 18 April 2014, the National Energy Commission (NEC) held the second meeting of its kind after the first gathering in 2010. The NEC, which is led by China's prime minister, is the most powerful energy institution. Its board consists of officials from the central bank; other government bodies responsible for the environment, finance, and energy; state-owned enterprises (SOEs), etc. This latest meeting stressed the need to construct ultra high-voltage (UHV) electricity transmission lines as well as China's commitment to the use of nuclear energy. In addition, NEC reaffirmed the reform of the electricity sector, particularly by introducing the direct purchase and sale of electricity between generators and large consumers. Yunnan province was designated to pilot test the scheme immediately.

Reform Initiatives in 2014: Yunnan and Inner Mongolia

The country's policymakers recently gave Yunnan and Inner Mongolia the go-signal to implement the latest reform initiatives. These initiatives include the direct purchase and sale of electricity between large consumers and generators and the development of smart grids. One main reason these two regions were selected for this initiative is the presence of an oversupply of power in their areas. Yunnan's power supply is dominated by hydroelectricity, which accounted for over 70 percent of the total production in the area and is still growing rapidly (Figure 9.8). In 2013, total production and consumption of electricity in Yunnan reached about 196 TWh and 146 TWh, respectively.

Oversupply coupled with inadequate transmission facility means that some hydro power plants could not operate at full capacity. As the current design allows the users and suppliers to negotiate electricity sale prices directly, such negotiation is expected to lower the price of electricity so that the region may be able to develop some power-intensive industries. Meanwhile, transmission prices are currently set according to past practices. However, future prices are anticipated to be set through a public consultation process. The sum of the two (sale and transmission prices), plus some considerations to account for transmission power losses, would be the final electricity price.

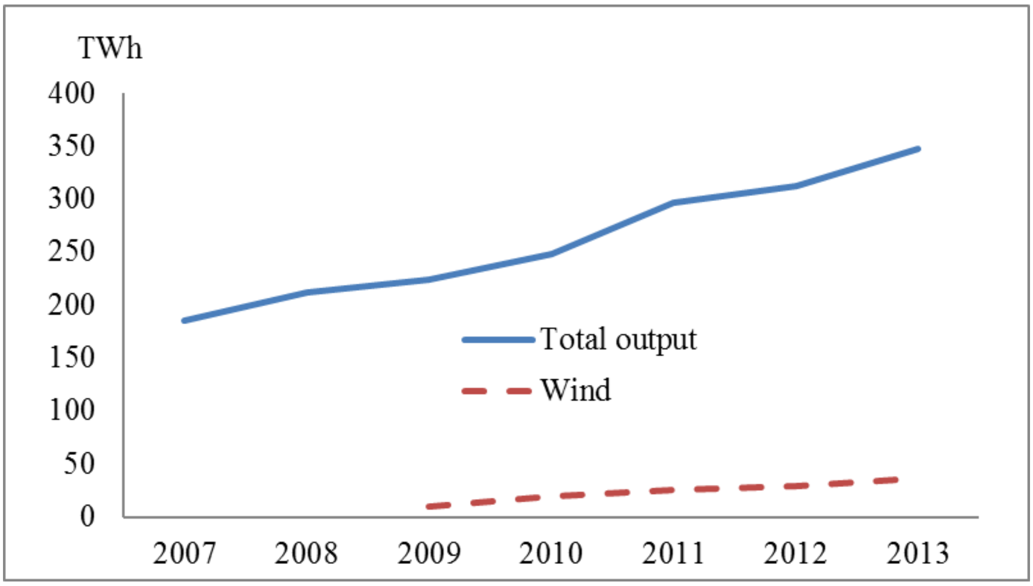
Figure 9.8: Electricity Production in Yunnan



Inner Mongolia also experienced a rapid growth in electricity supply, although slower than that in Yunnan (Figure 9.9). Wind power accounted for about 10 percent of electricity output in 2013. This share is expected to increase to 15 percent in 2015.[3] Reforms in this region will focus on developing smart grids as well as creating policies to accommodate the growth of renewable energies (REs). Currently, there is no other detailed information available yet. However, one known area needing immediate action is the excess supply of wind power in Inner Mongolia. This needs to be resolved so that wind farms will not have to shut down, as what had occurred in recent years. Thus, the connectivity between REs and inter-regional transmission are the priorities in this region.

[3] This number was cited in ASKCI (2014).

Figure 9.9: Electricity Production in Inner Mongolia



Challenges Ahead

Further reforms in China’s electricity sector have been well articulated by policymakers as well as scholars. But actions have been stalled in the aftermath of the power blackout in California and supply interruption at home during severe winter weather in 2008. The current energy policy priorities include the commitment to invest in nuclear power plants along the coastal area and the construction of UHV power lines for long distance power transmission. As mentioned earlier, Yunan and Inner Mongolia were selected as pilot-testing areas for direct power sales and purchase, but the implications of this test are yet to be assessed. The proposed new reforms will, however, face several challenges.

While the Electricity Act was promulgated in 1995 and revised in 2005, the Chinese power regulatory body (SERC) is vested with lesser authority compared to its supposed counterparts such as the Federal Electricity Regulatory Commission (FERC) in the United States. The SERC has to work with two other powerful institutions; namely, the National Development and Reform Commission (NDRC) and State-owned Asset Supervision and Administration Commission (SASAC). Through its offices, the NDRC is essentially responsible for energy pricing, strategic planning, project approval, and energy efficiency. Meanwhile, SASAC is the shareholder of the power sector's state-owned enterprises (SOEs), including the SGC and SCGC. Thus, the first challenge posed is how to strengthen the autonomy and authority of the regulatory body, the SERC, so as to truly separate regulation from business activities. In 2013, the State Council merged SERC with the National Energy Administration (NEA). This consolidation demonstrates the government's intent to have a single independent regulatory body for the electricity sector.

Nonetheless, the NEA still has to continue to work with NDRC and SASAC in one way or another. The recent NEC meeting indicates policymakers' resolve to carry out reforms in the power sector. As for its effectiveness, one just has to wait and see.

The second challenge is the need to unbundle power generation and transmission. In the 1990s, IPPs and other non-state invested power plants owned a large market share in power generation. This was due to incentives such as guaranteed returns, and prices and purchases offered to the private sector in the 1980s, when the Chinese economy was experiencing severe power shortage. Since the late 1990s, China's electricity market has become a buyers' market. When China became a World Trade Organisation member in 2001, the business environment for the private sector completely changed. Foreign investors were hit hard and started withdrawing from the Chinese market. Between 1998 and 2002, foreign investment share in the electricity sector fell from 14.3 percent to 7.5 percent (Chen, 2012). By the late 2000s, this share dropped to almost zero.

In the newly introduced scheme in Yunnan, the electricity price for a large power user is composed of two parts. One part is the agreed price directly negotiated between a generator and the consumer. The second part is the transmission cost determined currently by using historical information and eventually through public consultation. However, little has been discussed about the practice and conduct of public consultation. Its implementation is yet to be tested.

Third, pricing reform has been debated for years, but no action was ever taken. Several pilot tests for grid access bidding had been abolished. Since electricity generation is dominated by coal-fired technology, the price of coal matters in the determination of electricity prices. The coal market is now deregulated; hence, coal price is very much set by market conditions. However, the electricity price is still regulated. Thus the upstream and downstream prices in the electricity sector are delinked. This delink has caused a lot of problems.

Urgent pricing reforms are therefore needed. As a first step, large electricity users, initially in seven provinces, have been allowed since 2004 to directly purchase electricity from the generators. By 2013, this reform was expanded to more than 10 provinces (Smartgrids, 2014). However, the direct purchase arrangement did not catch on, and in fact was stopped in most regions by 2014. The main problem stemmed from the lack of coordinated reforms in other aspects of the electricity business (such as unbundling).

In early 2014, Chinese policymakers and their advisors initiated the same reform measure anew in Yunnan. They remain convinced that large electricity users should be allowed to directly purchase power from generators and that this practice could lead to further deregulation.

Finally, while electricity market integration is the key for effective reforms, China’s power market remains fragmented due to several factors:

1) Cross-regional trade in electricity is still limited, and institutional facilities for cross-regional trade are underdeveloped;
2) The price of electricity has been controlled by the government for a long time. The invisible hand of the market forces plays no role in price setting nor in affecting supply and demand;
3) Although the country’s grid networks are interconnected, the capacity and efficiency of long distance transmission of electricity is still constrained. Hydropower stations in Yunnan cannot operate at full capacity as surplus output cannot be sent out of the province. This is the same constraint seen in the wind and solar power production in Inner Mongolia, where the lack of smart grids hindered the utilisation of the existing facilities recently.

Conclusions and Policy Recommendations

China has made substantial progress in the electricity sector's deregulation, competition, and market integration. Major changes took place particularly in the late 1990s and early 2000s. These changes helped China overcome power shortage, complete the construction of a national grid and introduce multiple players in the electricity sector in a short period of time. However, the reforms seem to have stalled in recent years. China still has a long way to catch up with developed economies such as the United States, the United Kingdom, and Australia in market and institutional development in the electricity sector. Although the national grids are physically interconnected, the country's electricity market remains fragmented. Thus, the electricity sector has not realised the maximum benefits of an integrated market.

Because of the dominance of state-owned enterprises in the market, governments at various levels can always find ways to intervene in businesses. As a result, electricity pricing and business activities are still tightly controlled and the role of the markets' invisible hands is limited, not to mention complete unbundling of generation, transmission and distribution of electricity. To overcome these shortcomings, five policy recommendations are made. These cover pricing reform, institution-building, market integration, private participation and foreign investment, and renewable power sources.

Recommendation 1: Getting the electricity price right. China has made major efforts to improve the pricing mechanism of main fuels such as coal and oil. These fuels' domestic prices now move closely with international prices. However, electricity price in China is still tightly controlled and hence, cannot respond in a timely manner to the changing conditions in the fuel markets. This situation can affect the generation sector gravely when the fuel prices are very volatile.

It is important to introduce reforms in electricity pricing so as to get the electricity price right. A gradual approach could be adopted. The first step may be to allow direct negotiations between generators and large power users. The second step could involve the separation of the transmission business from the distribution side. The third step may be to expand the direct negotiation of sales to medium-size power users and allow for bidding for transmission. The policy makers' endorsement of the pilot schemes in Yunnan and Inner Mongolia is encouraging and a step toward the right direction.

Recommendation 2: Building an independent regulatory institution. Successful implementation of electricity sector deregulation in major economies such as the United States and the United Kingdom started with the establishment of an independent regulatory body. In China, the electricity sector is now composed of multiple players. China has been successful in the corporatisation of the electricity businesses initially. In terms of regulatory responsibility, multiple parties (NEA, NDRC, and SASAC) are also involved. None of those institutions can function independently of each other. This has come about partly due to the historical role of NDRC in central planning. Formerly called the National Planning Commission (NPC), the NDRC was responsible for the country's economic plans and strategies. Under the current regime, the NDRC maintains some of the functions of the old NPC. Therefore, vested interests make it impossible for either of the trio to have the ultimate authority in electricity regulation. Here is where there is a need to consolidate the regulatory tasks for execution by a single, independent body. China's telecommunication sector has been relatively successful in deregulation and may be able to offer lessons for the electricity sector.

Recommendation 3: Promoting electricity market integration. While the main power grids in China are physically interconnected, the Chinese market is still fragmented. This is largely due to the monopoly of the grid companies and the highly regulated nature of the entire sector. An integrated electricity market would help smooth demand and use regional resources more effectively. Also, given China's vast land area, infrastructure development becomes vital for the efficient transmission of power over long distances. The country's current plan to build several ultra-high voltage transmission lines across the nation seems to be the right move.

A more integrated market can help maintain stable supply and price of electricity, which is often a prerequisite for the introduction of drastic reforms. Thus, market integration and reforms mutually re-enforce each other.

Recommendation 4: Expanding the role of private players. In the 1990s, the private sector (particularly foreign IPPs) played an important role in helping overcome supply shortage and capital inadequacy in the Chinese market. However, ever since China became a WTO member in 2001, preferential policies towards private investment have been removed, leading almost all the private players to move out of the country's electricity sector. State-owned enterprises have now become the main players, mainly because their government connection helped them cope with large losses during bad times. This outcome is against the aim of reform efforts in the electricity sector. Thus, government policies are urgently needed to remove barriers to private participation and to invite non-SOEs back to the power sector.

Recommendation 5: Encouraging the development of renewables. China still overwhelmingly relies on fossil fuels for electricity generation. To control environmental pollution and meet the country's international climate change commitments, renewable energy should play an important role. In particular, China is currently enjoying the growth of hydropower, which is the main non-fossil source of power. When hydropower resources are exhausted, renewables will be the only source of growth in non-fossil energy. Renewable resources are, however, only available in certain conditions and their exploration only becomes economically feasible if technology is available or if supported by specific government policies. In the case of Inner Mongolia, for example, wind farms are not fully utilised because of infrastructure deficiency or lack of government support.

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CHAPTER 10

Enhanced Measurement of Energy Market Integration in East Asia: An Application of Dynamic Principal Component Analysis

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As a part of the initiatives to enhance cooperation between ASEAN and its dialogue partners, the energy market integration (EMI) in East Asia has been under way for over a decade. Despite the efforts exerted by countries in the East Asia Summit (EAS) region, little research has been done to measure the extent of the EMI's progress. This paper innovatively applies the dynamic principal component analysis to measure EMI and its evolution in the EAS region between 1995 and 2011. The EMI is measured from all the five dimensions that have been identified in literature: (1) energy trade liberalisation; (2) investment liberalisation; (3) energy infrastructure development; (4) domestic market openness; and (5) energy pricing liberalisation. Results show that significant progress has been made for the EMI in the EAS region, although there are cross-country disparities in different aspects. According to the level of progress made in the past, further efforts towards EMI in general should focus on liberalising national markets, then phasing out fossil fuel subsidies and finally, liberalising investment regime. Some mechanisms have to be developed to keep national level market liberalisation under monitoring. Certain countries that lagged behind in EMI may have to catch up and learn from either their past experiences or from other nations as well as focus their efforts on their relatively weak dimensions.

Key Words: Dynamic Factor Analysis, Energy Market Integration, East Asia
JEL Classification : C1, Q4, R1

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Introduction

Most countries in the East Asia Summit (EAS) region have long been cooperating on energy endeavors to sustain their economic growth. For example, even before the first ASEAN Declaration in August 1967, Thailand and Lao PDR had already signed their own energy agreement. Since 1990, the scope of the regional energy integration has broadened to cover all energy products and went from bilateral to multilateral cooperation. Beyond ASEAN, many institutional cooperation frameworks have emerged in East Asia under the principle of ASEAN centrality in the past decades such as the ASEAN Plus One, ASEAN Plus Three (ASEAN plus China, Japan, and South Korea), and EAS. Considerable progress in the areas of energy security, oil markets, renewable energy, and energy efficiency and conservation has been made as a result of the cooperation through the ASEAN plus Three process and more recently, the EAS process (Shi and Kimura, 2010, 2014; Shi and Malik, 2013).

To further enhance cooperation between ASEAN and its dialogue partners, the implementation of the energy market integration (EMI) in East Asia has been undertaken for over a decade. Energy market integration in the EAS region moved ahead in five areas: (a) trade liberalisation; (b) investment liberalisation; (c) development of regional energy infrastructure and institutions; (d) liberalisation of domestic energy markets; and (e) energy pricing reform---in particular, the removal of fossil fuel subsidies (Shi and Kimura, 2010; 2014).

So that governments can be guided on the right policies on EMI, there is a need to measure how individual countries are aligned with the EMI dimensions. Despite the efforts already made by countries in the EAS region, little research has been carried out on how to measure the EMI's progress.

Needless to say, there were previous studies that attempted to look at how the EMI fared (Sheng and Shi, 2011, 2013; Yu, 2011). The measure by Yu (2011) is cross-sectional and thus has not demonstrated the dynamics. Without such dynamics, the measurement cannot shed light on what policy initiatives to prioritise. Sheng and Shi (2011, 2013) have succeeded in measuring the dynamics of EMI, but their studies only focus on two dimensions: trade liberalisation and competitiveness in the domestic markets. Other dimensions of EMI have not been measured. Neither are the dynamics of these dimensions explored because these studies do not concentrate on the involvement of EMI itself.

This paper attempts to use some newly developed statistical methods---namely, the dynamic principle component analysis (dynamic PCA) and the information tree technique---to analyse the progress of EMI across countries and over time. The study aims to build an index system by using the principal component analysis approach to measure the status of the EMI process of each EAS country without knowing the weights for each dimension.

To contribute to the existing literature, this study aims to enhance the measurement of each dimension of the EMI and, for the first time, provide a comprehensive measurement of such integration in East Asia. Breaking down the EMI into such areas as institutional arrangement, physical infrastructure, and energy pricing, etc. helps identify the appropriate policy initiatives to take in the EAS region as well as aids each country's policymakers in determining how they must prioritise their own EMI efforts.

The next section of this study introduces the complexity of the EMI, which underscores the need for concise and clear indicators of its progress. The third section explains the methodology and data, followed by the presentation of the empirical results in Section 4. Section 5 discusses the results and policy implications. The last section provides the conclusions.

Energy Market Integration in the EAS Region

Following a conceptual framework for studying EMI in East Asia as proposed by Shi and Kimura (2010, 2014), this study tries to measure EMI in five areas: (1) trade liberalisation; (2) investment liberalisation; (3) development of regional energy infrastructure and institutions; (4) liberalisation of domestic energy markets; and (5) energy pricing reform (in particular, the removal of fossil fuel subsidies). Shi and Kimura's recent review (2014) finds that a large number of attempts for policy reforms for bilateral/multilateral trade and investment liberalisation have been made. However, energy trade continues to be restricted by both trade and non-trade barriers. These barriers should be removed so as to achieve freer trade in the EAS region. In particular, investment is restricted in many EAS countries.

Ongoing and proposed energy infrastructure projects have been limited to the ASEAN and China, while institutional arrangements related to energy trade have not been well developed. Also, national leaders still have to resolve major challenges, such as the need to further liberalise the domestic energy market and remove fossil fuel subsidies.

Given the above framework, this section next summarises the latest developments on EMI in East Asia.

To start with, trade liberalisation has been strongly promoted in East Asia, with the ASEAN playing a leading role. By 2010, more than 99 percent of the tariff lines had been eliminated in the ASEAN-6 members; namely, Brunei, Indonesia, Malaysia, the Philippines, Singapore, and Thailand, and reduced steadily in the newer members Cambodia, Laos, Myanmar, and Viet Nam. As for energy trade, tariffs in mineral fuels were reduced dramatically between 1993 and 2010 (Okabe and Urata, 2012). The ASEAN has also entered into free trade agreements (FTAs) or economic partnership agreements (EPAs) with countries outside ASEAN, and has established FTAs with the Plus Six countries (Australia, China, India, Japan, South Korea, and New Zealand) (ASEAN, 2012). The ASEAN is also working towards the Regional Comprehensive Economic Partnership (RCEP), also known as ASEAN++ FTA. In East Asia as a whole, while trade in energy remains restricted by tariffs, the levels of tariffs substantially declined in the period 1995-2010 (Shi and Kimura, 2014).

A recent study on investment liberalisation in ASEAN countries (Intal *et al.*, 2011) shows that the foreign investment regime on the overall is relatively open, with five ASEAN members-states (AMSs) having overall liberalisation rates between 88 percent and 92 percent; three AMSs with a liberalisation rate of around 85 percent; and two others hovering around the 80 percent rate. Of the ASEAN countries, Malaysia, Cambodia, and the Philippines boast the most open foreign investment regime, followed closely by Thailand

and Brunei, while Viet Nam and Indonesia have the most restrictive regimes. The restrictions on investment are often embedded in domestic regulations and thus cannot be resolved by international agreements alone (Shi and Kimura, 2014).

Proposed energy infrastructure projects are concentrated within the ASEAN region plus China, partly because the other Plus Six countries of the ASEAN, excluding India, are somewhat physically disconnected. However, with the development of more infrastructure such as marine transportation and liquefied natural gas (LNG) terminals, networks of energy infrastructure may be expanded to other countries, such as the Philippines and Australia in the case of LNG.

In general, there is still a long way to go in terms of interconnectivity and trade in the EAS electricity sector. The EAS lags behind Europe, where physical cross-border exchanges of electricity reached 10.3 percent of consumption in 2005 (Wu, 2012). Very little progress has been made towards harmonising technical specifications for the electricity trade, including design and construction standards, system operation and maintenance codes and guidelines, safety, environment, and measurement standards (Shi and Kimura, 2010, 2014).

Energy market liberalisation has been implemented in Australia, Japan, India, New Zealand, the Philippines, and Singapore. Meanwhile, in other countries, energy markets remain more or less restricted (Shi and Kimura, 2014). In terms of market integration, most EAS members are yet to develop a national electricity market. Meanwhile, when viewed in terms of their integration and unbundling of business activities, one end of the spectrum has Australia, New Zealand, and Singapore, where generation, transmission, distribution, and retailing operations have been fully disaggregated. The other end of the spectrum has Brunei, which has a fully integrated and stated-owned electricity sector. Meanwhile, China and India have kept the retailing and distribution operations integrated but separated the generation and transmission operations (Wu, 2012).

Within the ASEAN, the only country with a competitive electricity market is Singapore. Countries such as Malaysia and Thailand have deregulated the supply side but without a power purchase pool, while the Philippines has power pools in certain parts of the electricity network. Others such as Brunei and Lao PDR have strong stated-owned utility companies. In the gas sector, the transmission pipeline is usually owned and regulated by state-owned companies (Sahid *et al*, 2013).

Pricing reforms---in particular, the removal of energy subsidies---have been supported by policymakers and attempted by some countries. Energy prices are now broadly liberalised in Australia, Japan, South Korea, New Zealand, and the Philippines. The APEC leaders have declared that they would rationalise and phase out fossil fuel subsidies over the medium term (APEC, 2009).

Nations such as China, India, Indonesia, Malaysia, and Viet Nam have either planned or taken the initial steps to liberalise energy prices and remove subsidies for fossil energy. In China, its government is currently cutting the energy subsidies and promoting market-determined energy prices. In fact, China has implemented a market-based pricing for coal for the past few years (Yu, 2008). Malaysia plans to cut its fuel subsidies under a proposed five-year plan starting from 2010 (*The Straits Times*, 2010). In Viet Nam, although a road map for energy price increases has been formulated, the implementation has so far lagged behind (Kimura, 2011). Meanwhile, the Indonesian government planned a gradual reduction of total subsidies by an average of 10 percent to 15 percent per year from 2011 to 2014 (Mourougane, 2010), but the first attempt in March 2012 failed. In general, the removal of fossil fuel subsidies is a politically sensitive topic, as Indonesia and Malaysia had learned (*The Straits Times*, 2010). Therefore, the pricing reform has to be carefully planned and managed.

Due to economic development disparities, energy resource endowment, government regime and tradition, different countries have different situations for each dimension of the EMI. Furthermore, given the number of dimensions and diversification in each dimension, it is difficult for policymakers to comprehend what have been done and what still has to be done. The development of a quantitative assessment methodology will be useful for policymakers to monitor the progress of the EMI.

The next section of this paper proposes a methodology for quantifying the progress of EMI. These quantitative scores can then be used by policymakers as an indicator to measure their own work against and to identify leading policies that can be implemented in their own countries.

Methodology: Dynamic Principal Component Analysis

The principal component analysis (PCA) is a method to identify patterns in data and to express the data in a way that highlights their similarities and differences. The method seeks the linear combinations of the original variables such that the derived variables capture maximal variance. In particular, as highlighted by Shlens (2005), it can be completed via singular value decomposition (SVD) of the data matrix. Since patterns can be hard to find in data of high dimension (i.e., where the luxury of graphical representation is not available), the PCA is a powerful analytical tool that allows one to form a comparable index across countries under the condition that there is no explicit weight available. Detailed mathematical derivations on this can be read from previous papers of Sheng and Shi (2011, 2013), and Song and Sheng (2007). Meanwhile, this section will proceed to explain how a dynamic PCA analysis can be applied to measure the EMI process in the EAS region.

The Basic Model: A Dynamic PCA Analysis

To date, the static PCA method has been widely used in policy analysis (Shlens, 2005). Examples can be seen in Sheng and Shi (2011, 2013), Song and Sheng (2007) and Yu (2011). However, there are some difficulties in applying the method to measure the EMI's process in the EAS region from the empirical perspective. This is partly because the concept of EMI may involve too much information originating from different dimensions, plus the unknown potential effects on the final measurement can continue to change over time.

To solve this problem, statisticians developed a simple method called the dynamic PCA analysis or the dynamic factor analysis, to construct an index with the unknown weights for aggregating various driving factors. Mathematically, such a measurement of the EMI can be simplified into the following two-equation model

$$EMI_t = \lambda(L)F_t + e_t \tag{1}$$

$$F_t = \Psi(L)F_{tl1} + \eta_t \tag{2}$$

where EMI_t represents the unique measure of (or an outcome index for) EMI at time t capturing all the potential determining factors; F_t is a vector of n variables $(f_1, f_2, \cdots, f_n)$ representing various possible factors that could affect or determine the progress of EMI; z $\lambda(L)$ is a coefficient matrix that represents the potential contribution of various factors at different time period t to the EMI measure. The model defined by Equations (1) and (2) significantly differs from the previous studies in that it considers the fact that all the EMI determining factors are changing over time. Thus, these factors' changing pattern over time must be restricted. In doing so, $\Psi(L)$, the matrix used to define the trans-temporal movement of each determining factor, is specified. Finally, it is to be noted that both $\lambda(L)$ and $\Psi(L)$ are unknown and can change over time and thus, should be retrieved from the real data.

Applying the above model to practice may incur a problem called "curse of dimensionality". In other words, since there are two dimensions in the structure of determining factors $(f_1, f_2, \cdots, f_n)$---the cross-section dimension (i.e., $r_1, r_2, \cdots, r_n$) for different countries or regions, and the time series dimension (i.e., $t_1, t_2, \cdots, t_n$)---one cannot use the unconstraint entropy method to retrieve the weights for each determining factor along the two dimensions. Thus, two assumptions have to be made: (1) that each pair of cross-sectional observations is independent of each other; and (2) that the residual of the EMI measure is time contingent. The two assumptions can be further defined in two equations as
can be further defined in two equations as

$$E(e_t \eta'_{t-k}) = 0 \text{ for all } k \tag{3}$$

$$E(e_{it}e_{js}) = 0 \text{ for all } s \text{ if } i \neq j \tag{4}$$

Estimation of Equations (1) and (2) can be made either by using the maximum likelihood estimation combined with the Kalman Filter (Sargent and Sims, 1977) or by using the extraction of principal components (Stock and Watson, 2002). Recently, some studies (for example, Angelini et al., 2008) further suggest that the two methods be combined for a more efficient estimation---a process that is defined as the dynamic PCA or the dynamic factor analysis.

In the newly proposed estimation method, the fundamental difference is that determinant factors and their lags will be explicitly considered as the state vector such that the two-equation estimation system (i.e., Equations 1 and 2) is transformed into a three-equation system:

$$EMI_t = \Lambda F_t + e_t \tag{5}$$

$$\Phi(L)F_t = G\eta_t \tag{6}$$

$$d_i(L)e_t = v_{it} \tag{7}$$

where i refers to the i th determinant factor. Estimation of Equations (5) to (7) may take three steps.

First, one may apply the static PCA method to the panel data to estimate the biased contribution matrix Λ . In doing so, all information from cross-sectional and trans-temporal dimensions is treated equally. The residual that contains information related to the time-series or trend change can be calculated by using the estimated EMI_t minus ΛF_t.

Second, the obtained residuals are used as the dependent variable to regress with various determining factors, so as to identify the uni-variate auto-regressors. Specifically, the time-series analysis method (including the vector auto-regression estimation technique) should be used.

Third, the obtained uni-variate auto-regressors are implemented back to the first step to adjust the observations of all determinant factors and re-do the static PCA analysis. The results obtained would thus be reflecting the trans-temporal change in trend.

Estimation Strategy and Determinant Factors

Given the dynamic PCA method, the next step is to specify the estimation strategy and the determinant factors that should be used to measure the EMI and its changes across countries over time. Because information from different aspects may generate different impacts on the index aggregation process, this study has classified first all EMI determinant factors into different groups. Specifically, an EMI index was measured by aggregating a set of indices, each reflecting the five dimensions of EMI across the EAS countries.

Principal component analysis (PCA) was applied twice in the study:

- First, the PCA was applied to generate five indices for each of the five dimensions of EMI and then again to combine these indices into an overall index of EMI status. Under PCA, each index is a weighted linear combination of the input variables where optimal weights are selected to best account for the variation in the selected variables. This differs from previous studies measuring EMI status, wherein each type of factors is equally weighted in constructing the final index.
- Second, the aggregated index is further added up by using the same procedure to reflect the cross-country disparity in EMI level.. This will provide useful insights into the EMI's dynamic path.

The EMI index scores for each country were standardised between zero and five. A higher overall ranking implies a higher capacity to adapt to change; hence, greater resilience in the face of external pressures. Conversely, regions with low overall scores are potentially more vulnerable to change.

In measuring the EMI index, the information tree technique will be applied to decompose the aggregate index into different components so as to identify the role of different factors. The method uses a general non-linear function form (i.e., high-rank polynomial series) to build up the causal relationship between the EMI index and its potential determinants. This way, the drivers of EMI and the marginal contribution of each driver can then be identified.

Data and Estimation Strategy

The analytical framework proposed in Section 2 is consistent with that of previous studies (Sheng and Shi, 2011; Yu, 2011). Each of these five dimensions will be measured by at least three variables using dynamic PCA method. Data used for this study mainly comes from *World Development Indicators* (World Bank, 2013), UN Comtrade, and some other data sources. Variables were initially identified through a preliminary scoping study (See Song and Sheng, 2007) and selected based on the discussion on EMI process in Kimura and Shi (Shi and Kimura, 2010, 2014). These variables generally reflect the status of EMI in each country in the EAS region.

The different cross-country and time-series database come from a total of eight sources, including both censuses and surveys, collected from 1995 to 2011. Twenty variables are then selected based on their ability to intuitively inform one of the five dimensions. These variables, their expected relationship with the measured dimension, and data source are listed in Table 10.1.

Table 10.1: Variables Employed To Measure Each Dimension

Dimension	Variables To Be Used	Expected Sign	Source
Energy trade liberalisation	Mean of fuel trade	+	UN Comtrade
	Trade efficiency	+	Sheng & Shi, 2011
	MFN tariff	-	UN Comtrade
	Total energy self sufficiency (ESI, 1-1)	-	ERIA ESI
	Energy imports, net (% of energy use)	+	WDI
Investment liberalisation	Domestic credit to private sector (% of GDP)	+	WDI
	Interest rate spread (lending rate minus deposit rate, %)	-	WDI
	Market capitalisation of listed companies (% of GDP)	+	WDI
	Foreign direct investment, net inflows (% of GDP)	+	WDI
Energy Infrastructure (connectivity) development	Electric power transmission and distribution losses (% of output)	-	WDI
	Electric power consumption (kWh per capita)	+	WDI
	Commercial energy access ratio (ESI9-1)	+	ERIA ESI
	Rural population (% of total population)	+	WDI
National market openness	Trade (% of GDP)	+	WDI
	Net taxes on products (current US$)/*data174 GDP (current US$)	-	WDI
	Energy imports, net (% of energy use)	+	WDI
Price marketisation (no energy subsidy)	General government final consumption expenditure (% of GDP)	-	WDI
	Consumer price index (2005 = 100)	+	WDI
	Total natural resources rents (% of GDP)	-	WDI
	Energy use (kg of oil equivalent per capita)	-	WDI

Empirical Results: Measured EMI in the EAS Region

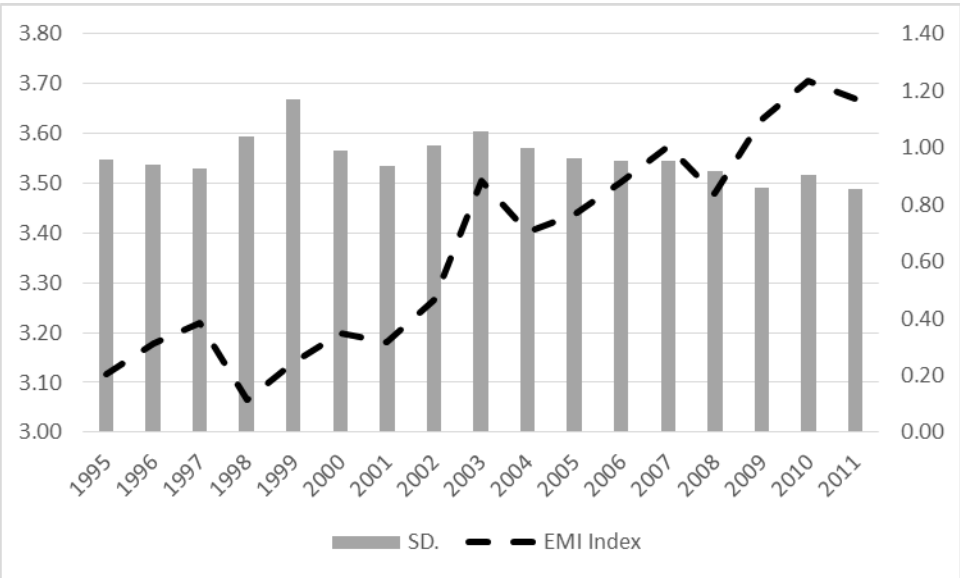
Using the dynamic PCA approach, the index for each EAS country involved in EMI is estimated by using the data from five dimensions (defined in the previous section) from 1995 to 2011. The empirical results on both the aggregate and country-specific measures are presented in Figures 10.1-10.3.

Energy Market Integration in the EAS Region: An Cross-country Overview

Over the past two decades, the energy market in the EAS region has become more and more integrated. The average EMI index (measured by DPCA) has increased from 3.12 in 1995 to 3.67 in 2011 while the standard deviation for the same periods declined from 0.96 to 0.85 (Figure 10.1). This suggests that the extent of integration has significantly improved.

Furthermore, since 2003, the standard deviation of the EMI index has reduced although the average EMI index continues to increase. This implies that member-countries have started to converge toward creating an integrated regional energy market. Incidentally, this was at a time when regional cooperation (in particular, economic and financial cooperation) was at its height following the Asia Financial Crisis. These seemingly related events imply that integration in the energy sector is coinciding with that of the whole regional integration.

Figure 10.1: Average Energy Market Integration in the EAS Region: 1995-2011

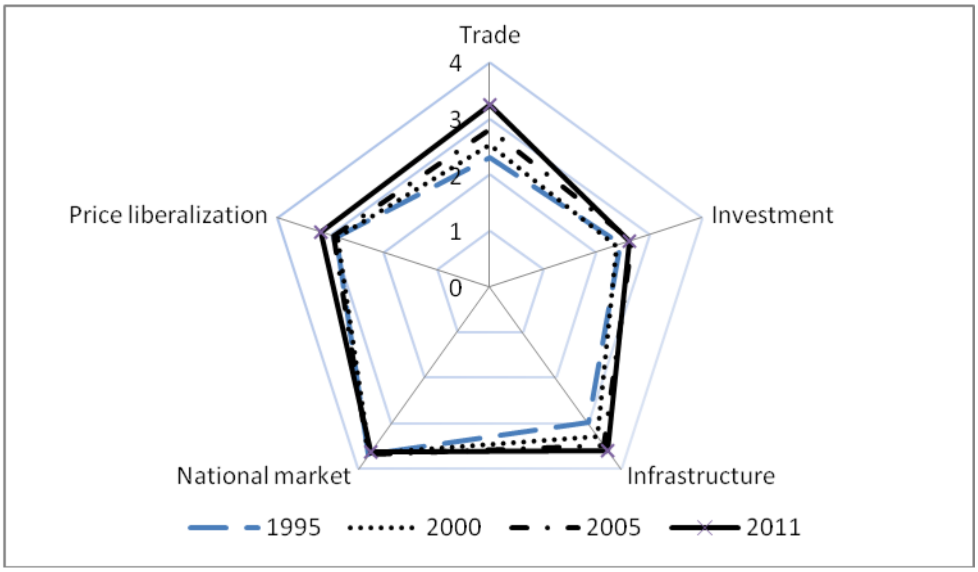


Note: The left axis is for DPCA and the right axis is for SD.

By further decomposing the average EMI index into the five dimensions: (1) energy trade liberalisation; (2) investment liberalisation; (3) domestic energy infrastructure development level; (4) national energy market liberalisation; (5) and price liberalisation level, one finds that the progress in the EMI in the EAS region came from improvements in all these aspects, although different dimensions might have played different roles over different periods of time.

A comparison among the EMI indexes from 1995 to 2011 shows that the EMI indexes for four dimensions (i.e., except national energy market liberalisation) have consistently risen over time (Figure 10.2). This implies that, in general, the improvement in EMI in the EAS region is following a relative balanced path. In particular, the EMI indexes for domestic energy infrastructure and energy trade exhibited a significant increase over time. Energy infrastructure experienced the largest progress from 2000 to 2005, while energy trade liberalisation significantly improved from 2005 to 2011. Meanwhile, price liberalisation and investment liberalisation had progressed during select years only. On the other hand, national energy market liberalisation made no progress during the period under study, which shows domestic market reforms are more challenging than the other four dimensions.

Figure 10.2: Relative Strength in Five Different Fields of Average EMI: 1995-2011



Trans-temporal Change in Country-specific EMI Levels

Given changes in the average EMI level, the next step is to investigate the contribution of each member-country in the regional integration of the energy market.

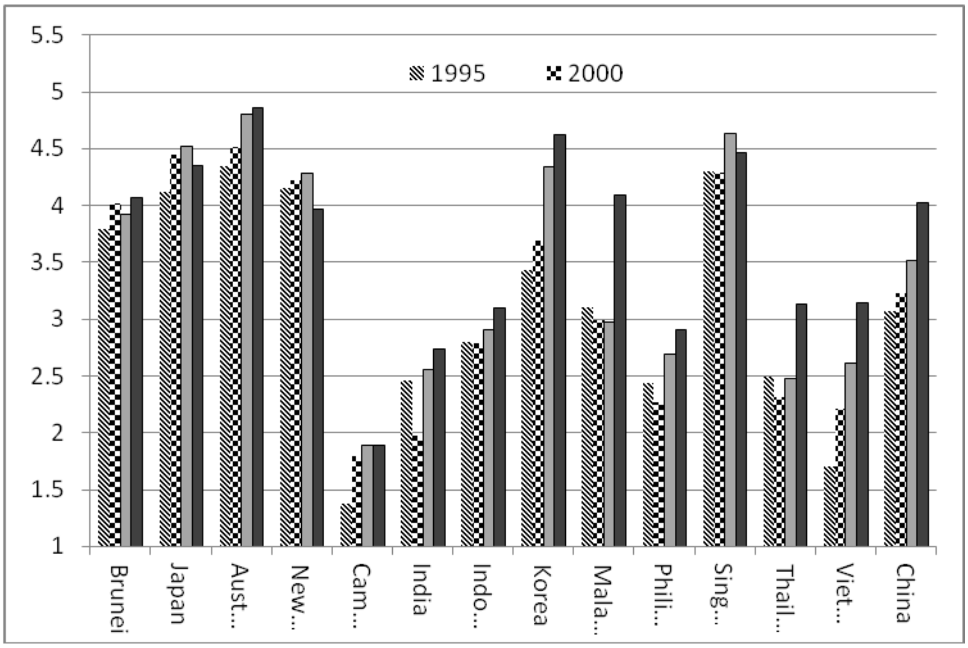
Figure 10.3 compares the EMI index for the 14 EAS countries (Lao PDR and Myanmar were not measured due to data limitations) from 1995 to 2011. Results show that most member-countries positively contributed to this process throughout the period.

In 13 countries (i.e., minus New Zealand), the aggregate EMI index increased during 1995-2011. Most also exhibit a monotonic increase in their EMI index, which means that that the integration has been progressing steadily among EAS member-countries. However, there are a few irregularities. India, Malaysia, the Philippines, and Thailand had a higher EMI index in 1995 that in 2000. Four ASEAN countries---Indonesia, Malaysia, Philippines, and Thailand---experienced a decline in their EMI index in 2000, which could be due to the Asia Financial Crisis.

New Zealand, too, experienced a decline in its EMI index during the sample period, although its 2011 index was higher than that of all ASEAN countries, except Singapore. This suggests that while New Zealand started with a high EMI index rating in 1995, it was not able to sustain its level over time.

Countries that are in the same economic development stages share a similar experience in their market integration efforts in the EAS region. High index levels were recorded in high-income countries（in terms of GDP per-capita）such as Australia, Brunei, Japan, South Korea, New Zealand, and Singapore. Nations that experienced rapid economic growth such as China, India, Thailand, and Viet Nam have also experienced quick improvements in their EMI index. Some ASEAN members such as Cambodia, Indonesia, and the Philippines showed little progress in their EMI index.

Figure 10.3: Comparison of the EMI Index across the EAS Countries in Selected Years



Different countries have achieved different improvements over time. Australia, Japan, and Singapore consistently remained in the Top 4 throughout the sample period. The largest jump in ranking was made by South Korea and Viet Nam, probably due to their more active contributions to regional market integration over the past two decades. On the contrary, New Zealand recorded the biggest decline in ranking. India and Indonesia also fell in ranking, which shows their failure to keep pace with the frontier countries. In comparison, China and Viet Nam managed a relatively higher rank in 2011 (Table 10.2).

Table 10.2: Ranking of EAS Countries, 1995 and 2011

1995 Rank	Country	Index	2011 Rank	Index		Change in Rank
1	Australia	4.350	1	Australia	4.862	
2	Singapore	4.308	2	South Korea	4.621	+4
3	New Zealand	4.151	3	Singapore	4.461	-1
4	Japan	4.128	4	Japan	4.356	
5	Brunei	3.799	5	Malaysia	4.095	+2
6	South Korea	3.434	6	Brunei	4.073	-1
7	Malaysia	3.109	7	China	4.024	+1
8	China	3.072	8	New Zealand	3.970	-5
9	Indonesia	2.806	9	Viet Nam	3.147	+4
10	Thailand	2.501	10	Thailand	3.129	
11	India	2.466	11	Indonesia	3.100	-2
12	Philippines	2.436	12	Philippines	2.908	
13	Viet Nam	1.703	13	India	2.736	-2
14	Cambodia	1.383	14	Cambodia	1.895	

Discussion and Policy Implications

Improvements were seen in all five dimensions of the EMI during the sample period. However, such progress is not balanced among the five dimensions. Trade and infrastructure have been advancing consistently and significant. This is no surprise as infrastructure development has always been aligned with economic development and improvement in quality of life. Infrastructure development is also less controversial than other dimensions of EMI. Trade liberalisation, too, has been progressing well in the EAS region due to the proliferation of free trade agreements.

On the other hand, price liberalisation and investment liberalisation saw little progress from 1995 to 2000 but improved after 2000. Price liberalisation gained some momentum after 2005, which could be due to an increasing awareness on the costs of fossil fuel subsidies and the related surging world oil prices. The political will to remove subsidies has slowly been gaining grounds over the past few years, as evident by APEC and G20 leaders' declarations to phase out fossil fuel subsidies. However, in practice, such fossil fuel subsidies persist, suggesting major challenges ahead.

National market liberalisation, however, saw no progress during the sample period. This means that EMI is mainly constrained by "behind-the-board" barriers. A liberalised and open domestic market---a prerequisite towards deeper energy integration---is hindered by many domestic factors such as political environment, social acceptance, development level, and government's capability. All these need to be addressed if EMI is to be achieved. Efforts made towards achieving regional EMI will touch on these tough and sensitive issues nowadays. Despite the non-intervene principle of the ASEAN and EAS cooperation, some mechanisms have to be developed to keep national market liberalisation under monitoring.

Most EAS member-countries in the study exhibited a monotonic increase in their EMI index, although some ASEAN countries lagged behind their peers. The high correlation between the EMI index and economic development level suggests that there are significant potentials for regional cooperation among countries at different levels of development.

Conclusion

This paper uses the dynamic principal component analysis to measure the EMI and its change in the East Asia Submit region from 1995 to 2010from five different dimensions. Results show that significant progress has been made in all dimensions of the EMI in the EAS region, although there are cross-country disparities in different dimensions. Furthermore, between 1995 and 2011, the extent of the integration had significantly improved, with all member-countries positively contributing to this process throughout the period.

The study finds that trade liberalisation and infrastructure development have progressed quite well; thus, little extra attention is needed on these. Investment liberalisation, however, needs to gain further momentum, while price liberalisation needs concrete actions to continue the momentum gained after 2005. Thus, the removal of behind-the-board barriers need to be pushed by the regional block.

Areas for future EMI efforts, arranged by priority, are: national market, fossil fuel subsidies, and energy investment. Countries that have lagged behind can also learned from their peers in terms of improving their own EMI levels.

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CHAPTER 11

Electricity Price Impacts of Feed-in Tariff Policies: The Cases of Malaysia, the Philippines, and Thailand

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Electricity market integration in the ASEAN requires the (1) development of the regional power infrastructure; (2) establishment of a regional power market; and (3) strengthening of national policies and regulatory frameworks that stimulate the development of national markets for renewable power generation. Among the countries in the region, Malaysia, the Philippines, and Thailand have advanced in terms of incentivizing the private sector to invest and increase the deployment of renewable energy technologies. However, one of the main barriers to renewable energy deployment is that its generation is more expensive than those from conventional energy resources. Thus, a higher deployment of these technologies would increase the financial burden of electricity ratepayers, particularly the lower-income households. The paper, thus, examines the implications of the feed-in tariff policies on electricity prices in these countries and reviews the measures introduced to minimise impacts of the existing tariff design on low-income households. Key conclusions of the study include the following: (1) At the outset, a political will to address the impacts of feed-in tariffs is essential; (2) Regulatory support measures for renewable energy ought to be taken as separate from the main ratemaking regulation; (3) Each regulatory approach has certain limitations but each could be addressed by specific measures available in the policy toolbox; (4) There is a need to establish a well-coordinated feed-in tariff program; and (5) Regulatory requirements vary depending on the electricity market structure. However, in competitive electricity markets, additional measures are needed to mitigate the impact on low-income households.

Keywords: Electricity market integration, electricity supply market structure, electricity price regulation, renewable energy policy, feed-in tariff, feed-in adder, tariff impacts.

Introduction

Among the key objectives of the ASEAN Economic Community for the energy sector are the integration of electricity markets, and open trade of renewable energies (ASEAN, 2008). Electricity market integration helps optimise the use of resources, improve regional energy security and stimulate trade, financing, technology and knowledge transfer within the region. The trade of hydropower generation is one of the foundations of electricity trade in the ASEAN region, and to extend this to other renewable energy resources requires the (1) development of regional power infrastructure; (2) establishment of a regional power market; and (3) development of the national market for renewable power generation (Chang and Li, 2013).

The economics of interconnection will determine how the ASEAN Power Grid (APG) will develop, while the dynamics of trade within ASEAN will determine the progress of market integration. This grid is subdivided into the northern system (covering the Greater Mekong Sub-region), the southern system (covering Malaysia, Singapore, and Indonesia) and the eastern region (covering Brunei, Indonesia, Malaysia, and the Philippines) (Hapua, 2014), Based on the current developments in the ASEAN's electricity trade, electricity market integration will most likely evolve from the growth of the three sub-regional markets, with the Greater Mekong Sub-regional market being the most developed (Pacudan, 2014).

In expanding renewable energy trade in the region, the development of national markets for renewable power generation and the strengthening of policies and regulatory frameworks that promote public-private partnerships in the deployment of renewable energy technologies are equally important.

One of the main barriers to renewable energy deployment is the higher capital investments required in its technologies. Relatedly, the cost of renewable power generation is higher than those from conventional power generation. These affect electricity prices and pose a financial burden to residential electricity consumers, particularly lower-income households. This is particularly relevant in ASEAN countries, where a significant number of the population is within the lower-income consumer category.

Malaysia, the Philippines, and Thailand have recently introduced feed-in tariff schemes that promote private sector investments on grid-connected renewable energy technologies, and are funded by electricity ratepayers. The paper reviews existing electricity market structures, electricity pricing policies and feed-in tariff policies, and analyses measures introduced by these countries to reduce the financial burden of feed-in tariff on low-income households.

Electricity Supply Market Structure and Institutional Arrangement

Because of disparate economic structures, levels of economic development levels, as well as political, institutional, and cultural conditions and orientations, the electricity supply industries in Malaysia, Thailand, and the Philippines are at various stages of market liberalisation and structural reforms. These industries are continuously evolving from a monopolistic, vertically integrated electricity supply model to an "enhanced" single-buyer model in Thailand's case; "managed market" single-buyer model for Malaysia; and open access and retail competition in the Philippines.

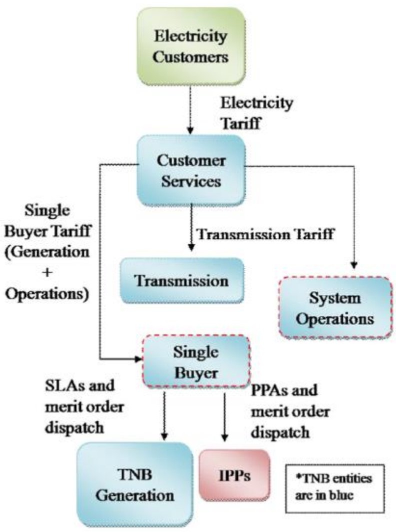
Malaysia

With three independent grid systems, Malaysia's electricity supply industry remains to be a single-buyer model with a competitive generation market but vertically integrated monopolistic transmission, distribution, and supply market in three geographic regions. The Tenaga Nasional Berhad (TNB) operates in Peninsular Malaysia, Sabah Electricity SDN Berhad (SESB) in Sabah, and Syarikat Sesco Berhad (SESCO) in Sarawak. These utilities are investor-owned although the government maintains the majority shareholding (Malaysia Country Report, 2013). The three utilities carry out mainly the generation, transmission, distribution and supply in their specific territories. In the 1990s, the government opened up the generation sector to private sector investments, allowing entry of independent power producers (IPPs).

Among the three geographic regions, Peninsular Malaysia has around 96 percent of the country's total electricity demand. Its TNB was established in 1990 as the result of the privatisation of the National Electricity Board (NEB), which during that time had consolidated key electricity supply industry functions. The TNB was corporatised and partially privatised through listing at the Kuala Lumpur Stock Exchange in 1992.

With the implementation of the incentive-based regulation (IBR) in 2014, Peninsular Malaysia's industry structure advanced from a single-buyer model to a "managed market model" (Figure 11.1). Under this model, five business entities under TNB are subjected to incentive-based regulations and required to unbundle and maintain individual regulatory accounts (Zamin and Ibrahim, 2013).

Figure 11.1: Peninsular Malaysia's Managed Market Model



Source: Zamin and Ibrahim (2013)

The Electricity Supply Act (ESA) of 1990 is the main legal framework that empowers the ministry responsible for the energy sector to regulate and issue directives on the industry (Jalal, 2009). The act was amended when the Energy Commission Act was passed in 2001, removing and transferring the regulatory functions to the Energy Commission (EC). The EC regulates the energy supply industry and enforces laws and regulations related to the energy sector, while the Ministry of Energy, Green Technology and Water is the main agency responsible for energy planning and policy formulation.

Thailand

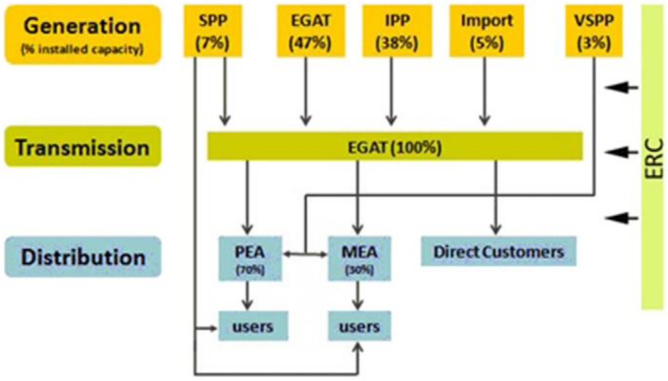
Over the past two decades various attempts were made to liberalise and restructure the electricity supply industry in Thailand. In the early 1990s, Thailand had a monopolistic and vertically integrated electricity supply industry. Its Electricity Generating Authority of Thailand (EGAT) consolidated the generation and transmission functions while the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA) were responsible for electricity distribution in Bangkok Metropolitan Region and in the provinces, respectively.

To address the lack of a national body to carry out energy planning, formulate policies and regulate the energy sector, the National Energy Policy Council (NEPC) Act was passed in 1992, and the National Energy Policy Office (NEPO) was established as its secretariat (Wisuttisak, 2010). The NEPO was later upgraded into a permanent department under the Office of the Prime Minister to become a regulatory body supervising and coordinating state-owned enterprises (SOEs). Pressured to reduce public sector debt, the government then opened up the electricity supply industry to private sector investments. The NEPO promoted liberalisation of the power market and encouraged independent power producers (IPPs) and small power producers (SPPs) to participate in power generation. The EGAT Act was also amended in 1992 to accommodate IPPs and SPPs as well as to establish subsidiary IPP companies. In the late 1990s, a NEPO plan to liberalise and privatise the electricity supply industry, transforming the industry structure from a single-buyer model to a wholesale and retail competition, was approved by the government.

The energy landscape transformed with the change of government in early 2000. The new government restructured its ministries and established the Ministry of Energy (MOE) in 2002 to be the new energy sector's policy-making, regulatory and executive body. The NEPO was downgraded to become the Energy Policy and Planning Office (EPPO) under the MOE. With this, the establishment of the competitive electricity market was abandoned and an "enhanced" single-buyer model was implemented in 2003 instead (Wisuttisak, 2010). This enhanced model was similar to the established structure during that time except that it called for the unbundling of accounts of EGAT's generation and transmission business as well as ring fencing the system operator and the relationship between generation side and system operations side (Bull, 2012).

There were also attempts to corporatise and list EGAT at the Stock Exchange of Thailand since 2004. Two royal decrees were passed by the government to provide the legal framework for corporatising the utility but met opposition from various stakeholders. The Supreme Administrative Court revoked the said decrees and nullified the corporatisation of EGAT in 2006 (Wisuttisak, 2010).
Still, the lack of an independent regulatory body remained a concern in the country. The National Legislative Assembly, thus, passed the Energy Industry Act in 2007, whose objectives are to promote competition, encourage private sector participation and establish an independent regulatory agency that provides a new regulatory framework. The Energy Regulatory Commission (ERC) was created and tasked to supervise and regulate the electricity and natural gas industries. Figure 11.2 below shows Thailand's enhanced single-buyer electricity industry structure.

Figure 11.2: Thailand's Enhanced Single-buyer Industry Structure



Source: Tongsopit and Greacen, 2013

Philippines

Among the countries, the Philippines is the most advanced in terms of introducing electricity supply industry reforms. Its government unbundled the electricity supply industry, privatised public utilities and introduced wholesale and retail competition.
Prior to reforms, the National Power Corporation (NPC) monopolised the generation and transmission functions of the industry, while public and private distribution utilities and electric cooperatives carried out the distribution and supply functions. Energy sector regulation was carried out by the Energy Regulatory Board (ERB). Meanwhile, franchising of electric cooperatives was managed by the National Electrification Administration (NEA) (Antonio, 2013).

Due to NPC's lack of financing capability to meet the needed capacity and to operate its generation portfolio efficiently, the government issued Executive Order No 215 in 2007, thus allowing the participation of the private sector in electricity generation. Three years later, the Build-Operate-and-Transfer (BOT) Law (1990) was enacted, encouraging contractors to build and operate power generation facilities with assured reasonable returns on their investments. With demand outstripping supply capacities, the Amended BOT Law was enacted in 1992, which introduced new schemes and new concepts such as unsolicited proposal and negotiated contracts---both of which are deviations from the standard procurement procedures (Antonio, 2013). This was followed by the passage of the Electric Power Crisis Act in 1993, which empowered the Philippine president to enter into negotiated contracts and reorganise the NPC.

Almost a decade later, the NPC continued to accumulate total obligations of US$16 billion in 2001. Various sectors, including creditors, pressured the government to introduce reforms so as to avoid another power crisis. In 2001, the government introduced sweeping reforms with the passage of the Electric Power Industry Reform Act (EPIRA). The EPIRA called for the (1) unbundling of the industry; (2) deregulation of the generation sector; (3) establishment of the transmission company; (4) establishment of an independent regulatory body, which is the Energy Regulatory Commission; (5) creation of the wholesale electricity spot market; (6) implementation of retail competition and open access; and (7) divestment of NPC assets (Republic Act No 9136, 2001).

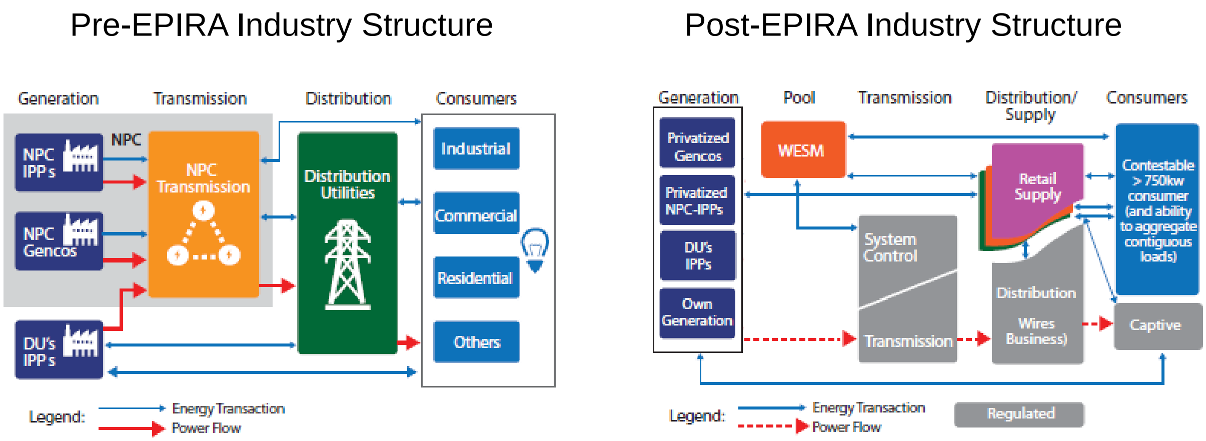
Despite delays in the implementation of EPIRA, considerable progress was achieved in the restructuring and privatisation of the electricity supply industry (DOE, 2013):

- The Power Sector Assets and Liabilities Management Corporation (PSALM) was established to manage and privatise NPC's generation assets and IPP contracts;
- The National Transmission Company (Transco) was established under the ownership of PSALM to assume the transmission function. The operation and maintenance of the transmission system was later privatised through concession. The National Grid Corporation of the Philippines (NGCP) was awarded the concession and became the power system operator.
- The distribution and supply functions were separated under a competitive electricity market structure. The distribution function is the common carrier business while the supply is the sale of electricity. Under retail competition, suppliers (other than the distribution company) can sell, broker, market or aggregate electricity to end-users. In 2012, the Energy Regulatory Commission declared that the preconditions for retail competition have been achieved, prompting the initial implementation of open access and retail competition.

- The wholesale electricity spot market (WESM) was established and started its operation in 2006 for the Luzon grid and further expanded in 2011 to the Visayas grid. The WESM was organised as a gross pool where all physical sales of electricity are offered in the pool and all purchases are drawn from the pool. This also includes electricity sold through bilateral contracts. The Philippine Electricity Market Corporation (PESM) was established as the administrator of WESM.

The pre- and post-EPIRA (current) industry structures are shown in Figure 11.3. Under the current structure, the transmission, system operations and distribution are monopolistic functions as well as regulated segments of the industry (Republic Act No 9136, 2001). Generation and supply are competitive segments and are not regulated. Power supply generators include IPPs and privatised NPC generation companies. These generators can sell either to the spot market (power pool) at market prices or directly to distribution utilities, retail suppliers and contestable consumers through bilateral and negotiated contracts. Captive consumers can only purchase power from retail suppliers, but contestable consumers can buy directly from the WESM, retail suppliers, and power generators.

Figure 11.3: Pre and Post-EPIRA Electricity Industry Structure in the Philippines



Source: Antonio (2013).

Key institutions involved in the administration of the electricity supply industry are the following:

- Joint Congressional Power Commission (JCPC), which is the main body with overall oversight of the implementation of EPIRA;
- Department of Energy (DOE), the policy-making body;
- Energy Regulatory Commission, the regulatory body tasked to encourage competition and protect consumers' welfare; and
- National Electrification Administration (NEA), which is tasked to promote rural electrification and prepare electric cooperatives to operate and compete in the deregulated electricity market.

Electricity Pricing

Electricity supply industry regulation has also evolved in these three ASEAN countries over the past decades. All three saw a growing need to separate the electricity supply policy-making function from the regulatory function and to establish independent regulatory agencies. Often, these are established as part of the overall legal framework that introduced liberalisation and competition in the electricity supply industry or sometimes as a follow-up law to the reforms act. The creation of the independent Energy Regulatory Commission was one of the key elements of the Electric Power Industry Reform Act (2001) in the Philippines. Malaysia passed the Energy Commission Act (2001) more than 10 years after the implementation of the Electricity Supply Act (1990). In Thailand, its own Energy Regulatory Commission was created in 2007, a year after the legal issues hounding the electricity supply industry were resolved.

Electricity Price Regulation and Tariff Setting

The scope of pricing regulation carried out in each country reflects the level of reforms undertaken to liberalise the electricity supply industries. Under their vertically integrated monopolistic markets, Malaysia and Thailand determine their electricity tariffs based on the financial requirements of the industry. In the case of the Philippines' competitive wholesale and retail markets, only the monopolistic segments see prices being regulated (although its regulatory agency provides guidelines and reviews the transactions in the competitive segments of the industry).

There is also an evolving trend to move away from rate-of-return base regulation and towards performance-based regulation. In addition, in the case of Malaysia and Thailand, ring fencing of industry functions and separating business entity accounts have become standard practices in price setting and regulation.

Malaysia

From the rate-of-return-base (RORB) regulation, Malaysia's Energy Commission moved towards the incentive-based regulation (IBR) in the last quarter of 2013 (i.e., the interim period starts in the financial year 2014 while the first regulatory period will be from 2015 to 2017) (Zamin and Ibrahim, 2013). The implementation of the IBR requires separate accounting for various business entities under TNB (i.e., generation, single-buyer generation and operation, transmission, system operation, distribution and retail). Under the new scheme, the electricity tariff consists of the base tariff and the imbalance cost pass-through (ICPT) (Energy Commission, 2013). The base tariff is determined based on target utility capital expenditures (CAPEX), operational expenditures (OPEX), fuel and power purchase costs and others, while the ICPT reflects the uncontrollable costs from base tariff such as variations in fuel and power purchase costs.

Each business entity's revenue requirement, which eventually is translated into average tariffs for electricity consumers, consists of the returns on assets (capped at the weighted average cost of capital or WACC), OPEX, depreciation, and tax. During one regulatory period, entities are given incentives to improve efficiencies related to operation, financing, and performance. Efficiency gains will be reflected in the next regulatory period and these business entities' share of benefits will be incorporated in the average tariffs.

Thailand

The electricity tariff in Thailand consists of the base tariff and the automatic tariff adjustment mechanism, which is also known as *Ft* (Ruangrong, 2013). In the past, the base tariff was estimated based on long-run marginal cost (LRMC), and tariff schedules were set by adjusting target revenue

requirements and performance targets. In 2011, the Energy Regulatory Commission implemented a new pricing policy that aims to be cost reflective and ensures financial stability of state utilities (EGAT, MEA, and PEA). With this new policy, the base tariff is estimated based on the state utilities' projected financial requirements for providing electricity services from generation to supply, with caps set on returns on invested capital (ROIC) (International Resources Group, 2013). The automatic tariff adjustment mechanism (Ft) is added to the base tariff to reflect unanticipated changes in costs (e.g., fuel and power purchase costs) plus other factors affecting investments such as feed-in adder and power development fund contributions. The revision of Ft is carried out every four months while that for the base tariff is done every regulatory period. One regulatory period in Thailand is equivalent to five years.
Thailand also applies a uniform national tariff---i.e., the same tariff is applied to all consumers throughout the country (International Resources Group, 2013). This policy requires cross-subsidisation between urban and rural consumers since distribution costs per unit in the former is lower than in the latter. Actual financial transfers have been carried out from MEA to PEA and from EGAT to PEA.

Philippines

As earlier mentioned, the Philippines has succeeded to unbundle the electricity supply industry and to introduce wholesale and retail competition. Electricity rates, consisting of (1) generation charge; (2) transmission charge; (3) distribution charge, supply and metering charge; (4) system loss charges; (5) subsidies; and (6) taxes and other levies, are therefore unbundled (DOE, 2013). The remaining monopolistic segments of the energy industry are regulated by the country's Energy Regulatory Commission, while the competitive segments are considered as pass-through costs.

Transmission and distribution charges are determined by the Energy Regulatory Commission using performance-based regulations. The methodology for setting these charges are stipulated in Rules for Setting the Transmission Wheeling Rates (RTWR), Rules for Setting Distribution Wheeling Rates (RDWR) for private investor-owned utilities (PIOUs) and

Rules for Setting Electric Cooperatives Wheeling Rate (RSEC-WR) for electric cooperatives.

Prior to the implementation of the performance-based regulation for transmission in 2003 and for distribution utilities in 2004, the Energy Regulatory Commission was adopting the cost-of-service regulation or rate-of-return base regulation. Now, under the performance-based regulation, the building block is the forecasted annual revenue requirements, which is then transformed into electricity tariffs (Energy Regulatory Commission, undated). One regulatory period in the Philippines is five years.

Generation charges are energy costs sourced from either WESM or bilateral contracts. Full recovery of these costs is allowed based on the formula set by the ERC. For system loss reduction charges, the Republic Act 7832 (Anti-electricity and Electric Transmission Lines/Materials Pilferage Act) of 1998 introduced a cap on the loss that can be charged to customers.

Subsidies include payments to recover the lifeline rates for low-income customers and discounts granted to senior citizens. Taxes and other levies include (1) value-added tax (VAT); (2) local franchise tax; (3) business tax; (4) energy tax; (5) universal charge; (6) loan condonation; (7) incremental currency exchange rate adjustment (ICERA); and (8) reinvestment fund for sustainable capital expenditures (DOE, 2013).

Lifeline Rates and Other Social Considerations

Regulators in the three countries also introduced progressive tariff designs for residential customers. That is, tariff rates progress with increasing consumption levels. Poorer households (lower consumption levels) pay lower rates than households with higher incomes (higher consumption levels) (Table 11.1).

Table 11.1: Electricity Tariff Rates

Malaysia TNB (1)		Thailand MEA (2)		Philippines MERALCO (3) Distribution charge only	
kWh	sen/kWh	kWh	Baht/kWh	kWh	Peso/kWh
1-200	21.80	1-15	1.8632	0-20	1.2225
201-300	33.40	16-25	2.5026	21-50	1.2225
301-600	51.60	26-35	2.7549	51-70	1.2225
601-900	54.60	36-100	3.1381	71-100	1.2225
Over 901	57.10	101-150	3.2315	101-200	1.2225
		151-400	3.7362	201-300	1.5798
		Over 400	3.9361	301-400	1.9170
				Over 400	2.5043

Note: (1) **Tenaga Nasional Berhad**, www.tnb.com.my, accessed 3 June 2014. (2) **Metropolitan Electricity Authority**, www.mea.or.th, normal tariff for consumption not exceeding 150 kWh/month, accessed 3 June 2014. (3) **Manila Electric Company**, www.meralco.com.ph, accessed 3 June 2014.

To promote universal access and alleviate the conditions of poor households, these countries have also introduced lifeline rates. The design of lifeline rates vary from country to country:

- In Malaysia, residential customers with total electricity bill of RM 20 (US$6.22) or below are entitled to a rebate of RM 20 per month (Tenaga National Berhad, 2014).
- In Thailand, the lifeline rate applies to consumption levels of 50 kWh or less per month. Households with up to this level of consumption need not pay their monthly electricity bills. Prior to the price regulation reforms in 2011, the lifeline rate was set at 90 kWh per month (Metropolitan Electricity Authority, 2014).
- In the Philippines, the lifeline rate varies from utility to utility. In the case of the Manila Electric Company (MERALCO), the lifeline discount structure is as follows: (1) Households consuming up to 20 kWh per month receive up to 100-percent discount on generation, transmission, system loss, distribution, supply and

metering charges; (2) Consumers of up to 50 kWh per month receive a 50-percent discount; (3) Households consuming up to 70 kWh per month are entitled to a 30-percent discount; and (4) Those using up to 100 kWh per month get a discount of 20 percent (Manila Electric Company, 2014).

Senior citizens (over 60 years old) in the Philippines also receive a special discount. The Energy Regulatory Commission sets the discount formula, which varies by utility.

Moreover, when new tariff rates were introduced in Malaysia in early 2014 in line with the implementation of the incentive-based regulation, there was no tariff increase imposed on those who consume up to 300 kWh per month (Tenaga National Berhad, 2014). Although residential consumers were expected to experience an average increase of 10.6 percent on their electricity bills with the introduction of new tariff rates, the zero-tariff hike actually benefited around 4.6 million of TNB's domestic consumers.

Feed in Tariff Policies

Feed-in Tariff Schemes

Feed-in tariff is one of the regulatory tools to promote private sector investments in renewable energy. Based on global experience, feed-in tariff is proven to be the most cost effective measure to achieve higher deployment of renewable energy technologies (Couture *et al*, 2010). Under this scheme, RE generators are guaranteed purchase of their power generation at a cost-based price with reasonable rate of return on investments over a long period of time.

Feed-in tariff policies are the main regulatory framework used by Thailand, Malaysia, and the Philippines to achieve their long-term renewable energy targets (Table 11.2). In fact, these are the first three ASEAN countries that introduced feed-in tariff schemes. Thailand's scheme is a premium payment also known as feed-in adder while those in Malaysia and the Philippines are the real feed-in tariff schemes. Thailand, however, has introduced a feed-in tariff program specific to roof-mounted and community-owned solar PV projects in 2013.

Table 11.2: Target Capacity Additions

Malaysia 2011-2030		Philippines 2011-2030		Thailand 2011-2021	
Biogas	390	Geothermal	1,495	Solar	3,000
Biomass	1,230	Hydropower	5,394	Wind	1,800
MSW	370	Biomass	277	Small	324
Small hydropower	430	Wind	2,345	Hydropower	4,800
Solar PV	1,371	Solar	284	Biomass	3,600
		Ocean	71	Biogas	400
				MSW	3
				New Energy	
TOTAL	3,781	TOTAL	9,866	TOTAL	13,927

Source: **Malaysia** – Handbook on the Malaysian Feed-in Tariff for the Promotion of Renewable Energy; **Philippines** – Renewable Energy Plans and Programs (2011-2030); **Thailand** – Energy in Thailand: Facts and Figures 2013.

Thailand

Among the three countries, Thailand was the first in the ASEAN to introduce a feed-in tariff policy scheme. The feed-in adder is one of the effective measures used by the government to achieve targets stipulated in its renewable energy policies. Initially, under the 15-year Renewable Energy Development Plan (2008-2022) introduced in 2009, the government aimed to increase the share of renewable energy to 20 percent of the total final energy consumption. This plan was, however, superseded in 2011 by the 10-year Alternative Energy Development Plan (2012-2021), which targets 25 percent of the total final consumption in 2021 to come from renewable energies (Department of Alternative Energy Development and Efficiency, 2014).

The feed-in adder program was approved by the National Energy Policy Council (NEPC) in 2006, but utilities started implementing only in 2007

(Tongsopit and Greacen, 2013). During this period, measures were simplified and streamlined. In 2009, bid bonds were introduced by the government in response to huge interests to apply in the program. In 2010, alarmed with the huge number of power purchase agreements, the NEPC reduced the solar PV adder rate and suspended the power purchase from solar power projects (Woradej, 2012). Studies on feed-in tariff policy started during this period and eventually, a feed-in tariff scheme for distributed solar PV generation was rolled out in July 2013. The scheme contain a target of 200 MW from rooftop solar PV to be installed in 2013 and 800 MW community-based projects to be done by the end of 2014 (Tongsopit, 2014).

The feed-in adder and feed-in tariff program is carried out by three state-owned utilities: EGAT, which purchases power from small power producers (SPPs); and MEA and PEA, which procure power from very small power producers (VSPPs) (Tongsopit and Greacen, 2013). Initially, project approvals were carried out independently by these three utilities. Since 2010, however, project approvals were transferred to the Ministry of Energy, where additional criteria for feed-in adder applicants such as projects' readiness in accessing loans, land, and government permits were introduced (Tongsopit and Greacen, 2013).

As to the new feed-in tariff policy for solar PV projects, the administration of the solar rooftop program is assigned to the Energy Regulatory Commission while that of the community ground-mounted solar program is given to Thailand's Village Fund and the Ministry of Energy (Tongsopit, 2014).

Thailand's adder program covers solar, wind, biomass, biogas, hydropower, and waste energy. Special power producers and VSPPs that utilise these fuel resources are eligible to participate in the program as long as they are from the private or public sector but not utility-owned. Adder is differentiated by technology, installed and contracted capacity size, and project geographic location. The SPPs and VSPPs sign a five-year renewable power purchase agreement with the utilities based on their avoided costs. To cover the actual cost of RE power generation, the feed-in adder is awarded to these generators. The adder support for wind and solar is for 10 years while that for other renewable energies is seven years. Table 11.A1 of the Appendix shows the adder schedule.

Malaysia

Malaysia is the second country in the ASEAN to launch a feed-in tariff program. Renewable energy was considered as the "fifth fuel" under its 8th National Plan (2001-2005) but despite various initiatives during this period, renewable energy accounted for less than 1 percent of the fuel supply mix in Peninsular Malaysia (Kettha, 2011).

In 2009, the Malaysian National Renewable Energy Policy and Action Plan called for the establishment of legal and regulatory framework as its first strategic thrust. As a result, the government passed the Renewable Energy Act (RE Act) and the Sustainable Energy Development Authority Act (SEDA Act) in 2011. The RE Act provides the legal framework for the feed-in tariff program while the SEDA Act mandated SEDA to be responsible for the development of renewable energy and implementation of the feed-in tariff program. The National Renewable Energy Policy and Action Plan aims to increase the share of renewable energy to 17 percent of the power capacity mix by 2030 (Harris and Ding, 2009).

Biogas, biomass, small hydropower, and solar PV are eligible RE resources under the feed-in tariff scheme. The SEDA announces the annual RE development quota and allocates it on first-come, first-served basis. Utilities are obliged to sign a power purchase agreement with quota allowance holders, to connect their facilities and dispatch their power generation to the grid. Feed-in tariffs differentiated by technology, capacity size, and bonus payments are provided for economic and developmental criteria such as locally assembled or manufactured technologies, installation in buildings or use as building materials, use of more efficient technologies, use of landfill or sewage gas, etc. Feed-in tariff payments are guaranteed for 21 years for solar PV and small hydropower; and for 16 years for biogas and biomass. To account for technological learning, degression rates that vary by technology were also introduced. Table 11.A2 of the Appendix shows the feed-in tariff schedules and quota allocation.

Philippines

The Philippines has limited indigenous fossil fuel resources and is highly dependent on imported energy. To promote renewable energy development, the government pushes for self-sufficiency to improve the country's energy security. In the Renewable Energy Plans and Programs (2011-2030) launched in 2011, the government aims to increase the total installed renewable energy power from more than 5 GW in 2010 to more than 15 GW in 2030 (DOE, 2011).

The legal framework for feed-in tariff in the Philippines was enacted as early as 2008 with the passage of Republic Act 9153, or the Renewable Energy Act of 2008. The Act stipulates various regulatory frameworks to promote renewable energy such as the renewable energy portfolio standards, renewable energy certificates, feed-in tariff, net metering and green energy market option. It established the National Renewable Energy Board (NREB), where public and private stakeholders-representatives are expected to provide technical assistance to the DOE and support the Energy Regulatory Commission in the implementation of the feed-in tariff and management of the RE Trust Fund.

The Philippines' Energy Regulatory Commission announced the Feed-in Tariff Rules in 2010 and issued the Guidelines for the Collection of the Feed-in Tariff Allowance (FIT All) and Disbursement of the FIT All Fund in 2013. In accordance with the rules, the NREB launched its proposed feed-in tariff rates in 2011. In 2012, the Energy Regulatory Commission announced the feed-in tariff rates for run-off river hydropower, biomass, wind, and solar that were much lower than those proposed by NREB. Details are shown in Table 11.A3 in the Appendix.

Feed-in tariff in the Philippines as differentiated by technology and feed-in tariff payment is for 20 years (DOE, 2013). A uniform degression rate of 6 percent per year was approved by the ERC. Annual adjustments will be made to reflect inflation and changes in the exchange rate.

As specified in the Act, the DOE is responsible for awarding RE service contracts and maintains the registry for RE participants. Also, the Transco is responsible for the settlement and payment of feed-in tariffs to eligible RE power plants. It is also with Transco that RE power developers sign the renewable power purchase agreements.

As of March 2014, around 90 projects with a total of 1.4 GW capacity have been awarded service contracts and registered by the DOE (DOE, 2014). As of July 2014, no project has been granted with feed-in tariff yet since commercial operation is one of the conditions for feed-in tariff awards. This condition differs from that in Malaysia, where feed-in tariff is awarded once the project owner receives the quota allowance; or in Thailand, where tariff is given once the readiness conditions have been satisfied (Sjardin, 2013).

Ratepayer Funding

Practices for funding feed-in tariff programs could be classified as either ratepayer funding, taxpayer funding, supplemental funding, or inter-utility cost sharing. There is a two-pronged reason for funding feed-in tariff programs: One is to ensure financial sustainability; the other is to minimize consumer impacts (Couture *et al.*, 2010). Globally, most feed-in tariff programs are found to be supported by ratepayers.

In fact, feed-in tariff programs implemented in the three countries in this study are all ratepayer funded. Feed-in tariff payments to RE power generators are being passed on to electricity consumers. Malaysia introduced an *ex-ante* feed-in surcharge to ratepayers, while the Philippines and Thailand have an *ex-post* feed-in tariff/adder charges.

Ex-ante proportional feed-in tariff surcharge

In Malaysia, the feed-in tariff program is funded by the surcharge on consumers' electricity bills. Until the end of 2013, the surcharge rate was 1 percent of the consumers' electricity invoices, but increased to 1.6 percent commencing January 2014 (Tenaga Nasional Berhad, 2014). Note, though, that only consumers with consumption levels of more than 300 kWh per month contribute to the feed-in tariff payments.

In this case, contributions are being collected prior to the development of an RE project. This approach has a limitation: that is, RE development is capped by the total amount that could be collected by the predefined percentage rate of the electricity invoices. This notwithstanding, the scheme provides a regulatory control on the burden of the feed-in tariff program by minimising the impact on target consumers.

Distribution utilities are responsible for collecting this surcharge from consumers. The collected feed-in tariff revenue is deposited to the RE Fund that was established under the RE Act and managed by SEDA. But since these same utilities are also responsible for paying to RE power producers, in practice they can either deposit the excess collection to the RE Fund or claim from the Fund in case that there is a shortfall in collections. Likewise, they are also entitled to charge some administrative costs in managing the feed-in tariff program from the Fund.

The Fund received an initial RM300 million from the Malaysian Treasury (Kettha, 2011).

Ex-post uniform feed-in tariff charge

In Thailand and the Philippines, feed-in adder/tariffs are collected after the development of the projects while the rate (in local currency per unit of electricity) is estimated based on the financial obligations of the utilities under contract with RE generators.

In the case of Thailand, the feed-in adder is one of the five components of the Ft charge (Ruangrong, 2013). Thailand's ERC, with the guidance from the National Energy Policy Council (NEPC), is responsible for setting these components of the Ft charge. The adder component, specifically, is determined based on the obligations from feed-in adder of utilities to SPPs and VSPPs. The Ft is being reviewed and adjusted every four months to reflect changes in EGAT’s fuel cost, power purchase cost, and impact of policy expenses. Currently, the MEA and PEA collect the feed-in adder, together with other charges, under the *retail* Ft charge from their consumers, while EGAT also collects *retail* Ft charge from its direct users. On the other hand, EGAT collects the *wholesale* Ft charge from MEA and PEA.

As part of the tariff adjustments made in 2011, Thailand's Energy Regulatory Commission passed a resolution to include the Ft rate of 0.9581 Baht/kWh in the base retail tariff, while the Ft charge starting July 2011 was reset to zero (Ruangrong, 2013). Thus, the existing Ft charge, which included the existing feed-in adder, became part of the retail base tariff. Since July 2011, the feed-in adder under the new Ft charge covers only those outside the base tariff.

Similarly, a feed-in tariff allowance is collected in the Philippines from all electricity ratepayers for renewable power generation. Under the Guidelines for the Collection of the Feed-in Tariff Allowance (FIT All) and Disbursement of the FIT All Fund (Energy Regulatory Commission, 2013), a uniform charge in Philippine Pesos per kWh will be estimated annually. Also, all consumers who are supplied from transmission and distribution networks in all on-grid areas in the country shall be billed to cover the financial obligations to eligible RE power generators. The guideline also stipulates the creation of a feed-in allowance fund to be administered by Transco.

Distribution utilities, electric cooperatives, the National Grid Corporation of the Philippines, retail electricity suppliers and the operator of the wholesale electricity supply market (WESM) will collect from their direct customers. The collected payments will be deposited in the feed-in allowance fund and disbursed by Transco, the party that signed the renewable power purchase agreements with the RE power generators.

Impacts on Electricity Bills

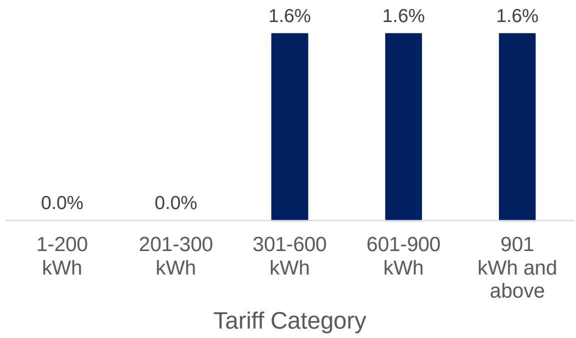
Malaysia

Malaysia is conscious of the potential implications of the feed-in tariff to low-income consumers. In the policy design, the government deliberately exempted lower-income households in the coverage of the feed-in tariff. Domestic customers with consumption level below 300 kWh per month are not required to contribute to the RE Fund (Tenaga Nasional Berhad, 2014). These represent around 67 percent of the customers of the distribution licensees.

The government places the burden on paying for the generation of green electricity on high electricity-consuming households. This is in line with the polluter pays principle, where those who cause more pollution (high electricity consumption) are expected to pay more to the RE Fund (Kettha, 2011). Also, the government hopes that as a positive effect of higher electricity rates, consumers will be incentivized to adopt energy-efficient measures, thus reducing their electricity consumption levels.

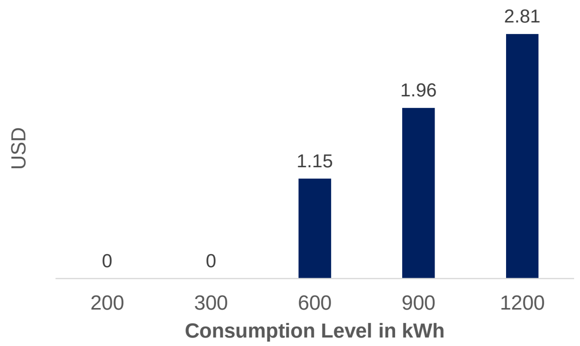
In addition, the *proportional* charge rate is neutral to all customers who will be paying contributions to the RE Fund since everybody is paying the same percentage rate on their electricity bills. This is shown in Figure 11.4.

Figure 11.4: Payment to RE Fund as Percentage Share of Household Electricity Bill (Starting January 2014)



In this study, the actual payments to be made by households at different consumption levels and based on current TNB electricity tariff rates are estimated. The calculated household RE Fund payments (in US dollar equivalent) according to consumption level are shown in Figure 11.5. In absolute terms, the payment rises along with increasing incomes but in terms of the overall burden, households pay the same percentage rate at their consumption level.

Figure 11.5: Payment to RE Fund by Household Electricity Consumption Level (Estimated based on May 2014 TNB tariff rates)



Philippines

In the Philippines, no special considerations for lower-income households were included in feed-in tariff rules and guidelines. The only concession relevant to the feed-in tariff allowance is the lifeline rate. Those who consume within or less than the identified lifeline rate are exempted from paying all other utility charges.

In contrast to Malaysia's case, the Philippines' feed-in tariff allowance is a uniform charge in terms of Philippine Pesos per kWh. This study thus estimates the impact of the uniform charge feed-in tariff allowance to electricity tariffs based on the methodology specified in the feed-in tariff allowance guidelines. The aim of this exercise is to proximate the indicative uniform charge that could be used in the analysis.

As of March 31, 2014, there are around 90 projects (11 biomass, 53 hydropower, 14 solar, 11 wind) with a total of 1.3 GW capacity in the registry of the Department of Energy. Assumptions on reasonable load factor levels were made and the demand projections in the Power Development Plan were used in the analysis. It was also assumed that all these projects would start operating in 2015. The feed-in tariff allowance on the first year amounts to PhP 0.45 per kWh. The feed-in tariff allowance will, however, decline over time as the projected electricity demand increases.

More recently, Transco filed an application to the Energy Regulatory Commission for feed-in tariff allowance of PhP 0.04057 per kWh covering the period 2014-2015 (Manila Standard Today, 2014). The study used this amount in the analysis.

Using MERALCO's tariff structure, the feed-in tariff allowance payment by consumption level is shown in Figure 11.6. Households with consumption level up to 20 kWh--- the cut-off consumption level for the lifeline rate---are exempted from paying the feed-in tariff allowance. For the rest of the consumers, the contribution to the feed-in tariff allowance increases as consumption levels rise. By taking the share of the feed-in tariff allowance payments to the total electricity bill (in this case, using MERALCO's residential bill at typical household consumption for May 2014), one finds that the uniform charge approach demonstrates a regressive feed-in adder rate design. Households with lower consumption levels contribute a relatively higher share of feed-in tariff payment to their electricity bills. This is shown is Figure 11.7.

Figure 11.6: Household Payment to Feed-in Tariff Allowance Fund by Consumption Level (estimated based on MERALCO's May 2014 Tariff level)

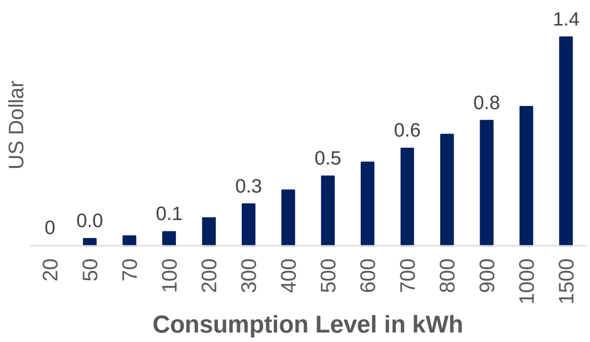
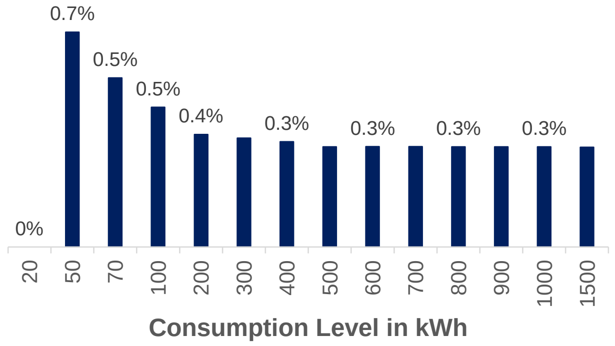


Figure 11.7: Household Payment to Feed-in Tariff Allowance Fund as Percentage of Electricity Bill (estimated based on MERALCO's May 2014 Tariff level)



Thailand

Thailand also has a similar uniform charge rate for feed-in adder. The adder values are being passed on to the consumers via the Ft charge. With the regulatory reset in July 2011, the previous period's adder charges were moved to the base tariff and only the adder charges from July 2011 to the present are reflected in the Ft charge.

In this study, the incremental adder from 2011 to 2013 was estimated based on projects that were commissioned after the regulatory resetting. The aim here is to proximate an indicative figure to be used in the analysis. The incremental projects were taken from the SPP and VSPP database, while the average load factors of such projects were estimated based on the Department of Alternative Energy Development and Efficiency's (DEDE) data. The national electricity demand used in the analysis is based on the Energy Policy and Planning Office's (EPPO) data. Thus, for 2013, this study estimates the equivalent uniform adder to be Thai Baht 0.053 per kWh.

Taking the MEA's current tariff structure, the estimated household adder contributions by consumption level is shown in Figure 11.8, while the shares of adder to the total electricity bill by consumption level is presented in Figure 11.9. The analysis shows that the uniform adder rate is slightly regressive. The share of the adder in the total electricity bill is slightly higher in households with lower consumption levels than those with higher consumption.

Figure 11.8: Household Payment to Feed-in Adder by Consumption Level (Estimated based on MEA's May 2014 Tariff Level)

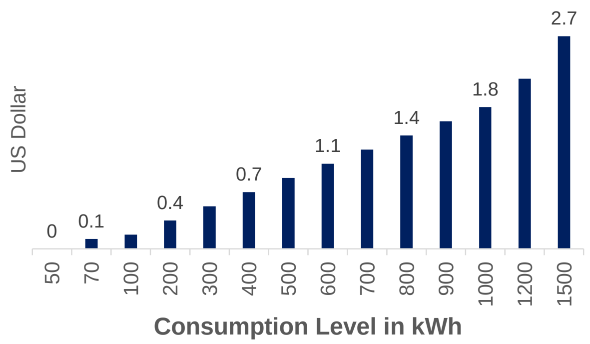
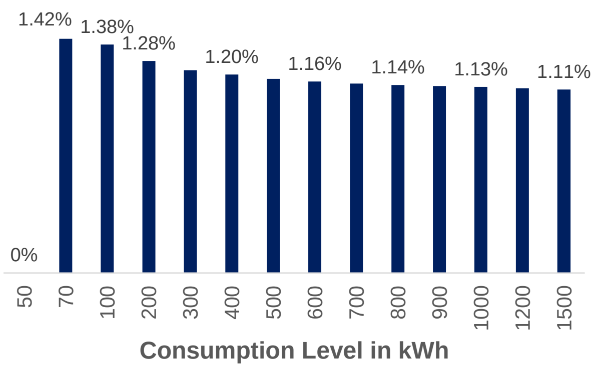


Figure 11.9: Household Payment to Feed-in Adder as Percentage of Electricity Bill (Estimated based on MEA's May 2014 Tariff Level)



Policy Analysis and Implications

Social Considerations in Feed-In Tariff Design

In Malaysia, the Philippines, and Thailand, concerns on the impacts of the feed-in tariff policies on electricity tariffs have long been expressed during their policy-making processes, but it is only in Malaysia where the social impacts on low-income households have become one of the key criteria in its feed-in tariff policy design and implementation. Malaysian policymakers, at the onset of the feed-in tariff policy design, had recognized social and perhaps political considerations and, thus, exempted households with consumption levels below 300 kWh per month in the feed-in tariff scheme. Political awareness and determination, therefore, play important roles in mitigating the potential impacts of the feed-in tariff policy on lower-income households.

Proportional and uniform charge rates

The study shows that a proportional charge rate results in a neutral design where the incidence of the surcharge is uniform to all consumers regardless of the consumption level while a uniform rate yields a regressive design, creating higher financial burden on households with lower consumption levels.

The ex-ante proportional charge rate offers better control with respect to social impacts but one of its shortcomings is that renewable energy development is capped by the total amount collected from the pre-defined charge rate.

On the other hand, schemes with uniform charge rates require that the annual energy project's development be well managed and controlled to mitigate any negative impact on consumers, particularly the poorer households. In the case of Thailand, the lack of coordination among implementing bodies and weak regulatory control in the past led to an unrestrained increase in power purchase agreements from solar PV projects (Tongsopit and Greacen, 2013). This resulted in higher estimated adder in the Ft charge and in the eventual suspension of the solar PV adder program in 2010 (Woradej, 2012).

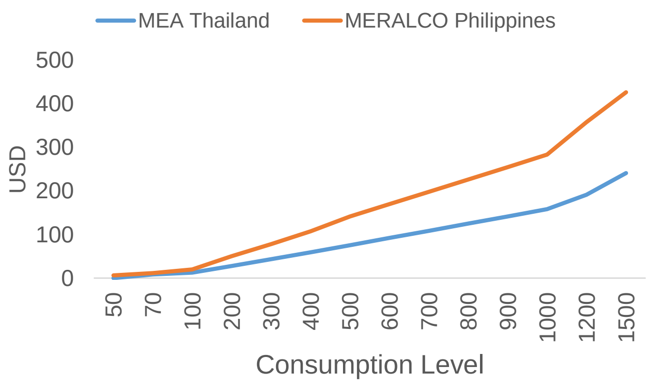
Tariff Structure and Level of Reforms

Thailand and the Philippines both have uniform charge rates but results show that the Thai adder scheme is less regressive than the feed-in tariff scheme in the Philippines. This can be explained by the difference in the design of tariff structures.

In Thailand, the whole industry is regulated. Its regulatory agency has control over the base costs that could be included in the tariff-setting process and can design a tariff structure that is more equitable to all consumers. Thus, Thailand's current tariff structure generates a much flatter curve for electricity payment against consumption levels (Figure 11.10).

Meanwhile in the Philippines' competitive electricity market, electricity rates are being unbundled according to different electricity supply functions. Only the monopolistic activities such as transmission, system operation and distribution functions are regulated; the rest are market determined. Also, except for the distribution charge and taxes, all other charges are uniform rates per unit of electricity. The uniform charge could pose a much steeper increase in electricity payments as the household's electricity consumption rises (Figure 11.10).

Figure 11.10: Electricity Bill by Consumption Level



A regulated industry structure has much room to adjust its tariff structure and make it more equitable to all electricity consumers. In contrast, it is clear that competitive markets will not respond to social needs; thus, regulatory intervention would be necessary. In the case of the Philippines, it appears that the current lifeline rates and senior citizen discounts are not sufficient to alleviate the impacts of its feed-in tariff scheme. Additional measures may need to be introduced to remedy the potential impact of the feed-in tariff allowance on lower-income households.

One option could be feed-in tariff allowance discounts similar to the existing lifeline rate discounts. This discount could be passed to other consumers as cross-subsidy; likewise, it could also be funded by the Renewable Energy Trust Fund as stipulated in the Republic Act 9153 of 2008.

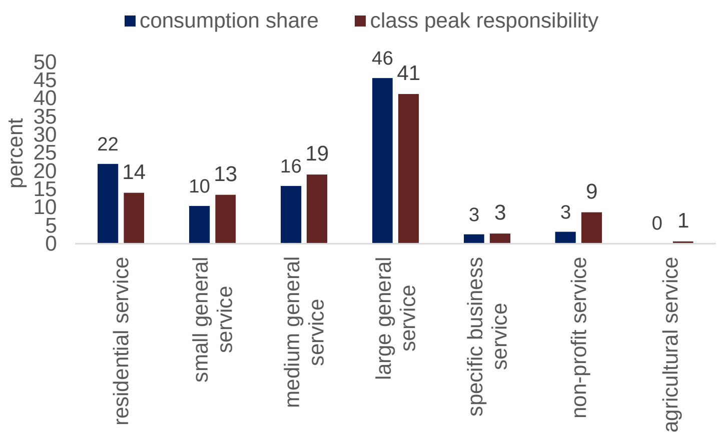
Adjustments Using Joint Cost Allocation Approach

In the uniform charge-per-unit approach, the overall contribution by each sector to the total feed-in tariff/adder corresponds to the total consumption share of the given sector. Under the cost allocation theory, the uniform charge per unit, while it is more equitable than the uniform charge per customer approach, does not differentiate the customers who make full use of renewable power generation, from those who do not. Neither does the uniform rate differentiate the types of services being provided by renewable energy facilities (Conkling, 2011).

One of the most common approaches to address this issue under the principle of joint cost allocations in electricity pricing is through the demand peak responsibility method. Under this approach, joint costs are allocated based on demand burden caused by each customer class. The demand burden is measured based on either "coincident peak" or "non-coincident peak" methods. These approaches are commonly used in allocating costs for base tariff calculations but could also be applied in allocating costs for feed-in tariffs. For example, under the "coincident demand peak responsibility method", the peak demand share of each customer class could be used as basis for allocating the feed-in tariff.

As shown in Figure 11.11, applying this principle in Thailand's case will further reduce the burden of the feed-in adders on residential customers (Woradej, 2012). With a uniform charge per unit, the residential sector's share of the total annual cost stands at 22 percent. On the other hand, by using the peak responsibility allocation, the said sector's share would drop to 14 percent.

Figure 11.11: Consumption Share Allocation Vs Class Peak Responsibility Allocation (Thailand)



Conclusions

This study reviews how Malaysia, the Philippines, and Thailand have promoted the use of renewable energy technologies using the feed-in tariff framework. It also looks at regulatory approaches and how passing the feed-in tariff/adder impacts electricity ratepayers.

Since there are various regulatory methods of charging feed-in tariff/adder to electricity consumers, each country's choice of method depends on the prevailing regulatory traditions and practices. Each framework has its strengths and weaknesses, but there are key lessons learned from this study:

- At the outset, political will and determination to address the potential impacts of feed-in tariffs are essential;
- Regulatory measures to promote deployment of renewable energy technologies must be considered separate from the main ratemaking regulation (i.e., feed-in tariff/adders are add-on to the base electricity tariffs).
- Each regulatory approach has certain limitations but these could be addressed by specific measures available in the current regulatory policy toolbox as well as by establishing a well-coordinated feed-in tariff program.

- Regulatory requirements vary depending on the electricity market's structure. Under regulated markets, there exists some room to adjust tariff structures so as to make the feed-in adder rates more equitable. In competitive markets, on the other hand, additional measures would be necessary to alleviate the impact of the feed-in adder on lower-income households.

This analysis would be very useful for other countries in the region to consider when designing policy frameworks on how to promote renewable energy deployment that will be funded by ratepayers.

Appendix

Table 11.A1: Thailand Adder Rates

Type of Renewable Energy	Adder in 2009	Adder Since 2010	Additional for Diesel Substitution	Additional in Top 3 Southern Provinces	Period of Support
	Baht/kWh	Baht/kWh	Baht/kWh	Baht/kWh	Year
1. Biomass					
≤1 MW	0.50	0.50	1.00	1.00	7
> 1 MW	0.30	0.30	1.00	1.00	7
2. Biogas					
≤1 MW	0.50	0.50	1.00	1.00	7
> 1 MW	0.30	0.30	1.00	1.00	7
3. Waste					
Fertilizer/landfill	2.50	2.50	1.00	1.00	7
Thermal process	3.50	3.50	1.00	1.00	7
4. Wind					
≤ 50 kW	4.50	4.50	1.50	1.50	10
> 50 kW	3.50	3.50	1.50	1.50	10
5. Hydro (mini/micro)					
50 kW ≤ 200 kW	4.50	0.80	1.0	1.0	7
< 50 kW	3.50	1.50	1.0	1.0	7
6. Solar	8.00	6.50	1.50	1.50	10

Source: Ruangrong, P. (2013)

Table 11.A2: Malaysia Feed-in Tariff Rates

Capacity	FIT Rate (RM per kWh)	Effective Period (Years)	Annual Degression Rate
1. Biogas≤ 4 W			
Above 4 MW ≤ 10 MW	0.32	16	0.05%
Above 10 MW ≤ 30 MW	0.30	16	0.05%
Use for gas engine with efficiency above 40%	0.28	16	0.05%
Use of locally assembled gas technology	+0.02	16	0.05%
Use of landfill or sewage gas as fuel	+0.01	16	0.05%
	+0.08	16	1.80%
2. Biomass			
≤ 10 MW	0.31	16	0.05%
Above 10 MW ≤ 20 MW	0.29	16	0.05%
Above 20 MW ≤ 30 MW	0.27	16	0.05%
Use of gasification technology	+0.02	16	0.05%
Use of steam-based generating systems with			
efficiency above 14%	+0.01	16	0.05%
Use of locally assembled gasification	+0.01	16	0.05%
technology	+0.10	16	1.80%
Use of MSW as fuel			
3. Small hydro			
≤ 10 MW	0.24	21	0%
Above 10 MW ≤ 30 MW	0.23	21	0%
4. Solar PV			

≤ 4 kWp	1.23	21	8%
Above 4 kWp ≤ 24 kWp	1.20	21	8%
Above 24 kWp ≤ 72 kWp	1.18	21	8%
Above 72 kWp ≤ 1 MWp	1.14	21	8%
Above 1 MWp ≤ 10 MWp	0.95	21	8%
Above 10 MWp ≤ 30 MWp	0.85	21	8%
Installation in building or building structures	+0.26	21	8%
As building materials	+0.26	21	8%
Locally manufactured or assembled PV modules	+0.03	21	8%
Locally manufactured or assembled inverters	+0.01	21	8%

Source: KeTTHA (2011)

Table 11.A3: Philippines Feed-in Tariff Rates

RE Technology	FIT Rate (PhP/kWh)	Degression Rate	Installation Target (MW)
Wind	8.53	0.5% after 2 years from effectivity of FIT	200
Biomass	6.63	0.5% after 2 years from effectivity of FIT	250
Solar	9.68	6.0% after 1 year from effectivity of FIT	50
Run-of-River Hydropower	5.90	0.5% after 2 years from effectivity of FIT	250

Source: Department of Energy (2013)

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CHAPTER 12

Trade-off Relationship between Energy Intensity—thus Energy Demand —and Income Level: Empirical Evidence and Policy Implications for ASEAN and East Asia Countries

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This study has been motivated by the recent shift of energy demand's gravity to Asia due to decades of robust and stable economic growth in the region. Said economic growth has correspondingly led to increases in per capita income in emerging economies in ASEAN and East Asia. Past empirical studies showed that energy intensity –thus energy demand-- tends to grow at an early stage of development. However, curbing the energy intensity remains central to green growth policy. Thus, this study formulates the hypothesis on whether energy intensity – thereby energy demand -- starts to fall as a country becomes richer. Based on this hypothesis, this study aims to investigate: (i) the non-monotonic relationship between energy demand and income levels in selected ASEAN and East Asia countries; (ii) the short- and long-run association of energy demand with price and income level; and (iii) the country performance in curbing the energy intensity. The study employs panel data model, pool-OLS, and historical time series data of individual countries with Vector Error Correction Model (ECM) for the analysis of the above objectives. The findings have suggested three major implications. One, it found that energy intensity --thus energy demand -- has a trade-off relationship with income level which contributes to the theory of energy demand. Two, energy demand has a trade-off relationship with income level, albeit the fact that each country has a different threshold level, implying that whatever the level of per capita income a particular country has, that

country can curb energy intensity if it has the right policies in place. And three, countries with persistently increasing energy intensity will need to look into their energy efficiency policies more aggressively to ensure that structural changes in the economy do keep the energy efficiency policy to its core.

Keywords: energy demand, energy intensity, income, price, energy efficiency, trade-off or threshold, ASEAN and East Asia.

JEL Classification: C30, Q40, Q49

Introduction

Energy has played a vital role in human history for the advancement of human development. Many studies have proved the strong relationship between economic growth and energy consumption. It is also noted that there has been significant progress in terms of curbing energy growth through the reduction in energy intensity in the world's developed countries. Based on the International Energy Agency (IEA) publication, *World Energy Outlook*, the efficiency improvements in power and end-use sectors and the shift from energy-intensive industries could explain the reduction in the energy intensity. Although the global rate of energy intensity has declined, however, this rate has considerably slowed down from 1.2 percent per year on average between 1980 and 2000, to only 0.5 percent per year between 2000 and 2010. This slowdown can largely be explained by the shifting gravity of energy demand to developing Asia which have relatively high energy intensities due to their reliance on energy-intensive industries and on coal-fired power generation (IEA, 2012). As the result of limited access to high-end and low carbon emitting technologies in the developing world, the energy intensity expressed as the amount of energy used to produce a unit of gross domestic product (GDP) tends to be much higher in developing countries than in OECD countries. Said slowdown can also be attributed to the worsening of the energy intensity in some parts of the Middle East (which has been increasing since the 1980s) due to the low energy price that discouraged the deployment of energy efficient technologies (IEA, 2012).

In the literature, energy intensity has been investigated globally in terms of its trend as a macro indicator of energy efficiency. Some of the studies focused on the contributing factors to reduce energy intensity over time. Wu (2010) found that the energy intensity in China declined substantially due to improvements in energy efficiency, but changes in economic structures affected energy intensity modestly. Chumbo and David (2008) also investigated the energy intensity in China and found the decline of energy intensity due to technological changes. Its finding on the role of structural change, though, disagreed with Wu's finding. Ning (2008) investigated the energy intensity in three provinces of China, and the results suggested that the provinces of Ningxia and Inner Mongolia with developed renewable energy industry and clean energy technology have increasing or almost constant energy intensity, while Liaoning which has a heavy industry base and does not have much renewable energy capacity experienced an energy intensity decrease. Kumar (2003) also investigated factors that are influencing industrial energy intensity in India and its major findings were that research and development (R&D) activities are important contributors to the decline in firm level energy intensity. Metcalf (2008) investigated energy intensity in the United State of America and its conclusions were that rising per capita income and higher energy prices have played important parts in lowering energy intensity. Based on the Energy Information Administration (EIA, 2012) report, the structural changes in the economy are major movements in the composition of the economy and in any end-use sectors that can affect energy intensity but are not related to energy efficiency improvement. However, efficiency improvement in the process and equipment can contribute to observed changes in energy intensity.

Galli (1999) has made the first attempt to estimate the energy demand functions, including the energy intensity, during 1973-1990 using a quadratic function of income. This kind of non-monotonic function could explain the u-shaped patterns in energy intensity as income increases. This method has been applied elsewhere in the literature for other purpose (see Han, 2008) when there is a belief that increasing income will likely induce a trade-off relationship with dependent variables, which in this case are the energy demand and energy intensity. Adopting the work of Galli (1999) and Han (2008), this study has three objectives, namely: (i) to investigate empirical evidence of some selected ASEAN and East Asia countries to see the extent or level of economic growth wherein both energy demand and energy intensity start to fall. In other words, to what level of per capita GDP does the energy demand and energy intensity start to reverse the trend; (ii) to assess the short and long-run association between energy demand and energy intensity, on one hand, and energy price and income, on the other, to test the theory of the energy demand; and (iii) to assess the country's performance of energy intensity with the assumption that energy intensity tends to rise and fall from one period to another period, and the sum of the energy intensity growth rate shall be "negative" if the country is on better performance of curbing energy intensity. The findings provide certain policy implications that would help accelerate various economies' goal of achieving a reduction in the energy intensity. They also imply the level of the energy efficiency in respective economies that would reduce the energy intensity.

The paper is organised as follows: the next section discusses the empirical model of the inversed U shape relationship between economic growth and energy intensity and energy demand. This is followed by the section on the data used in the model, and then by the section on results and analyses. The final sections provide the conclusions and policy implications.

Empirical Model

Trade-off Relationship between Energy Demand and Energy Intensity, and Income

In the theory of energy demand, income and price are assumed to be major determinants to explain the change of the energy demand. In previous literature, energy demand is generally affected by the different states and structures of economy of individual countries and other characteristics. Causality is also expected to run from income and price to explain the energy demand in both short and long run. However, time series data are likely to be non-stationary and thus suffer by the unit root or random walk. Therefore, the series are not integrated in order I (0), but are presumably integrated of the same order I (1) after the first differentiation.

This study proves that energy intensity is in fact the energy demand function. It starts the model of energy intensity which is a function of price and income, and finally derives the energy demand function from the energy intensity function. Other unobserved variables are captured in error term in the energy demand model.

Defining E_{it} as per capita of quantity of energy demand used for national production in country i *at* year t, and in this case represented by aggregated form of total final energy consumption (TFEC) per capita; and GDP_{it} as the corresponding per capita income in country i at year t, which takes the form of Gross Domestic Product at constant price 2005;

P_{it} is the energy price which has been adjusted to constant price by GDP deflator 2005.

The study assumes that Energy Intensity EI_{it} of use is a non-monotonic function of GDP_{it} and other variables. This assumption has been employed in the past study by Galli (1999) whose study focused on the non-monotonic relationship between national aggregate energy demand and income from 1973-1990. This assumption is the result of the fact that the tendency for energy intensity is to increase with output in low-income countries, and to decrease with output in high-income economies.

For the sake of this study, it could be that for some countries, the turning point (per capita income) may get faster in terms of timeline which could be an attribute of the work of energy efficiency and aggressive policy target in the region.

Since the data in this study are the panel data of the selected countries in ASEAN and East Asia, they shall thus be written as:

$$Log(EI_{it}) = \beta_0 + \beta_{i1} Log(P_{it}) + \beta_{i2} LogGDP_{it} + \beta_{i3} (LogGDP_{it})^2 + \varepsilon_{it} \qquad \text{(Eq.1)}$$

From equation (1), it is proved that the Energy Intensity is in fact the energy demand;

Since $Log(EI_{it}) = LogE_{it} - LogGDP_{it}$; thus the equation (1) can be re-written as:

$$LogE_{it} - LogGDP_{it} = \beta_0 + \beta_{i1} LogP_{it} + \beta_{i2} LogGDP_{it} + \beta_{i3} (LogGDP_{it})^2 + \varepsilon_{it} \qquad \text{(Eq.2)}$$

To avoid endogeneity, $LogGDP_{it}$ was moved from the left to the right hand side of the equation (2);

Thus the energy demand function is derived:

$$\boxed{LogE_{it} = \beta_0 + \beta_{i1} LogP_{it} + (\beta_{i2} + 1) LogGDP_{it} + \beta_{i3} (LogGDP_{it})^2 + \varepsilon_{it}} \qquad \text{(Eq.3)}$$

The coefficients β_{i1}; $(\beta_{i2} + 1)$; *and* β_{i3} in equation (3) are of interest to this study.

The equation (3) could be regarded as a complex function and as per capita GDP grows higher, this model implies that both energy demand and energy intensity have diminishing effects. In other words, energy demand will reach a point of saturation, and energy intensity will thereby reverse its trend. However, the estimation results from the equation (3) do not reflect the behavior or trend of an individual country because it was expected that in some countries, the diminishing effects of income on energy demand and energy intensity may take different values of per capita GDP. Therefore, equation (3) was also estimated by using time series data of each individual country. The model specifications for each time series of an individual country are therefore:

$$Log(E_t) = \beta_0 + \beta_1 Log(P_t) + (\beta_2 + 1) LogGDP_t + \beta_3 (LogGDP_t)^2 + \varepsilon_t \quad \text{(Eq.4)}$$

From equations (3) to (4) above, the trade-off point or the diminishing effects of income on energy demand and energy intensity in the above dynamic function are simply the first derivative with respect to per capita income. Thus $-\frac{(\beta_2 + 1)}{2\beta_3}$ is the trade-off point that could be a U shape or inverted U shape depending on the sign of the $(\beta_2 + 1)$ & β_3.

Short and Long-run Causalities of Energy Demand and Energy Intensity

From equations 3 and 4, this study is also interested in the causalities or associations between energy demand—thus energy intensity-- with covariates of energy price and income.

In this case, it is assumed that time series data are not stationary, but all variables are integrated of the same order I (1) after first differentiation. Thus, the co-integration test (see Annex 1) will also be performed before proceeding to the estimation of the model by Vector Error Correction Model (VECM).

If such co-integration exists, the error correction term in VECM will adjust (speed of adjustment) towards both short and long-run equilibrium.

For simplicity, $Log(E_t)$ will be written as e_t, in the lower case to represent the logarithmic function. Thus, the Error Correction Model of energy demand-thus energy intensity-- of each individual country could be expressed as:

$$\Delta e_t = a_0 + b_1 \Delta e_{t-1} + c_i \Delta p_t + c_2 \Delta p_{t-1} + d_1 \Delta gdp_t + d_2 \Delta gdp_t^{\ 2} + \delta s_{t-1} + U_t$$

(Eq.5)

Where $$\delta s_{t-1} = [e_{t-1} - (\phi_1 gdp_{t-1} + \phi_2 p_{t-1})]$$

If $\delta \prec 0$, then energy demand and energy intensity in the previous period overshot the equilibrium, and thus the error correction term works to push the energy demand and energy intensity back to the equilibrium. Similarly, the error correction term can induce a positive change in energy demand and energy intensity to the equilibrium (see Wooldridge, 2003).

Assessment of the Country Performance of Energy Intensity Over time

The study has been motivated by the observation that energy intensity tends to rise in one or few periods and fall in one and few periods. This phenomenon seems to be a fluctuation of rise and fall over time similar to the cycle of economic boom and bust. Therefore, one needs to have knowledge as to whether the economies are generally on a better or worse performance in terms of curbing the growth of energy intensity. With this notion in mind, the authors constructed the energy intensity growth rate with the following:

Energy intensity growth rate for any particular year, $$EI_{growth} = \frac{EI_t - EI_{t-1}}{EI_t} \times 100 = \frac{\Delta EI_t}{EI_t} \quad \text{(Eq.7)}$$

How does one know that a country is in a better or worse performance in curbing the energy intensity if the energy intensity growth rates are likely to fluctuate from period to period? Theory says that if the percentage fall of energy intensity is greater than the percentage rise of energy intensity, the economies generally perform better in combatting the energy intensity. Therefore,

$\sum EI_{growth} \prec 0$, if the economy performs better in curbing the energy intensity; and

$\sum EI_{growth} \succ 0$, otherwise.

Data and Variables

This study uses three datasets in order to get the variables of interest in the model. The first dataset comes from the Institute of Energy Economics, Japan (IEEJ) in which few variables are obtained such as Total Final Energy Consumption (TFEC) and crude oil price of Japan. Further, this study also uses World Bank's dataset called World Development Indicators (WDI) in order to capture a few more time series variables such as Gross Domestic Product (GDP) at constant price 2005, GDP deflator at constant price 2005 and population. The variable of the energy intensity is actually derived by dividing the TFEC in TOE to the GDP at constant price 2005.

Table 12.1 describes some characteristics of the variables used in the study and the patterns of year-on-year average growth rate of those variables.

Table 12.1: GDP per capita, Energy use per capita, Energy Intensity

Country	GDP per capita (a)			Energy use per capita (b)			Energy intensity (c)			
	1971	2011	Growth%* 1971-11	1971	2011	Growth%* 1971-11	1971	2011	Growth%* 1971-11	Growth%* 2000-11
Australia	18,129	36,585	***1.78***	2.51	3.33	***.72***	1.39	.91	***-1.03***	***-1.67***
China	150	3,120	***7.94***	.22	1.07	***4.10***	14.78	3.42	***-3.50***	***-1.92***
Japan	15,671	36,160	***2.15***	1.88	2.43	***.70***	1.20	.67	***-1.40***	***-1.43***
S. Korea	2,687	21,226	***5.36***	.42	3.18	***5.38***	1.55	1.50	***-.020***	***-1.83***
Philippines	845	1,433	***1.38***	.18	.19	***.39***	2.08	1.34	***-.95***	***-4.23***
Singapore	5,193	34,378	***4.91***	.51	4.69	***6.04***	.99	1.36	***1.14***	***1.99***
Thailand	594	3,158	***4.34***	.13	1.11	***5.66***	2.20	3.53	***1.27***	***1.28***
India	271	1,085	***3.57***	.08	.26	***2.96***	3.07	2.42	***-.52***	***-1.39***
Average	***5,443***	***17,143***	***3.93***	***0.74***	***2.03***	***3.24***	***3.41***	***1.89***	***-0.63***	***-1.15***

Note: (a) GDP per capita at constant price 2005
(b) Energy use per capita (TOE per capita)
(c)Energy intensity per $US 10,000 (at constant price 2005)
* Year on year average growth rate

It is observed that countries with high GDP year-on-year average growth rate tend to also have high growth rate of energy use per capita. These include China, South Korea, Singapore and Thailand. Generally, energy intensity has declined in most countries for year-on-year average growth rate, except in a few ASEAN countries. However, it could largely be explained by data problem since this study uses IEA data and Naphtha has been included in the energy balance of Singapore and Thailand.

Results and Analyses

Table 12.2a shows the results by estimating equation 3 of the panel data in countries studied. In addition, the pooled-OLS model was run to compare the results with panel model specification in equation 3. Since the Huasman test suggested that there is enough evidence to reject the null hypothesis, the authors then accept the alternative hypothesis under the assumption that "fixed effect is appropriate". Therefore, Table 12.2a shows only the fixed effect coefficient estimates along with the pool-OLS for the comparison purpose. Because the authors believed that each country may experience different paths or relationships between energy demand and energy intensity with increasing per capita income, equation 4 was also estimated by using each time series data as shown in Table 12.2b. Finally, Table 12.2c shows the results by estimating equation 5 for the short and long-run association of energy demand and energy intensity with its covariates using Vector Error Correction Model.

The non-monotonic relationship between national aggregate of per capita energy demand--thus the energy intensity-- and per capita income in the countries studied indicates the level of saturation of per capita energy demand due to increasing per capita income. Table 12.2a shows that ASEAN and East Asia as a group tends to have trade-off relationship between energy demand and income. However, each country may have a different path or relationship between energy demand and income.

Table 12.2b shows trade-off relationship between energy demand and income. It is shown that Australia, China, South Korea and the Philippines have reached a saturated level of per capita energy demand when per capita income had reached US$ 32,215 for Australia, US$ 3,020 for China, US$ 17,414 for South Korea, and US$ 1,185 for the Philippines. These mean that Australia, China, South Korea and the Philippines have already experienced the decline of per capita energy demand-thus the energy intensity- because per capita income in these countries in 2011 were US$ 36,585 for Australia, US$ 3,120 for China, US$ 21,226 for South Korea, and US$ 1,433 for the Philippines (see Table 12.1).

In contrast, while countries like Singapore, Thailand and India showed trade-off relationship between per capita energy demands-thus energy intensity-- with per capita income, these countries have yet to experience the decline of the per capita energy consumption because the trade-off points of these countries are exceeding the current per capita income. Table 12.2b shows that Singapore, Thailand and India shall not have reached a saturated level of per capita energy demand when per capita income has not reached US$ 51,359 for Singapore, US$ 6,214 for Thailand, and US$ 1,463 for India. These mean that Singapore, Thailand and India have not yet experienced the decline of per capita energy demand because per capita income in 2011 in these countries were US$ 34,378 for Singapore, US$ 3,158 for Thailand, and US$ 1,085 for India (see Table 12.1). Lastly, Japan seems to have experienced the decline of per capita energy demand at the early stage of development when its per capita income reached less than US$ 19,326 (see Table 12.2b). Corrolarily, it also seems that per capita income of Japan exceeding US$ 19,326 likely increases its per capita demand of energy. Therefore, the current situation seems that Japan is likely to have increased per capita energy demand.

The non-monotonic relationship between energy intensity-thus energy demand-- and per capita income in the countries studied implies a shift of structural changes in the economies towards environmental friendly energy use practices. This has been made possible through the availment of improved technologies at both demand and supply sides of energy when per capita income has reached a certain level where an individual could possibly afford better technologies and energy products such as end-use appliances.

Figure 12.1a-h explains the fluctuation rise and fall of energy intensity growth rate in the countries studied. All countries seem to have similar patterns of the rise and fall of the energy intensity growth rate. This means that countries with experience of better performance of energy intensity in one period may or may not continually lead to a better performance in the next one or two periods. When energy intensity is in the downward trend, it is expected that it will rise again soon. However, if the economies are on the level of efficiency improvement, one might expect to see that the energy intensity growth rate of “negative sign” is higher than the “positive sign”. This will lead to the sum of energy intensity growth rate with “negative sign” if the country performs better in curbing energy intensity, and with “positive sign”, if otherwise.

In addition, Table 12.1 shows that amongst countries studied, Australia, China, Japan, South Korea, and the Philippines have generally done well in terms of curbing the energy intensity. However, few countries in ASEAN may need to speed up policies to reduce the energy intensity so that in the long run, they could bring in the negative growth in energy intensity. There could be data problem as well when analyzing the energy intensity in some ASEAN countries as IEA data include Naphtha into the energy balance table. However, on average, countries studied as a group have achieved above 0.63 percent and 1.15 percent year-on-year of the energy intensity reduction for the period 1971-2011, and 2000-2011, respectively. It is also important to note that for all countries studied, both per capita energy consumption and income have grown. Table 12.2c shows that both coefficients in the error correction term of energy demand-thus the energy intensity-- are significant and negative. The joint t-test of the coefficients of price and its lags, and income and its lags show that they are all jointly significant. These mean that energy demand-thus energy intensity-- have both short and long-run associations with energy price and income. This is important to confirm for the theory on energy demand and to ensure that this study's model specifications of non-monotonic function of energy demand have both short and long-run associations with price and income. Table 12.2c shows that both price and income have jointly adjusted towards a long-run equilibrium to explain the energy demand at different speeds of adjustment. In this case, both price and income have induced the speed of adjustment at 23 percent for Australia, 33 percent for China, 31 percent for Japan, 15 percent for South Korea, 14 percent for the Philippines, 37 percent for Singapore, 23 percent for Thailand, and 21 percent for India towards long run equilibrium, respectively.

Table 12.2a: Coefficient Estimates of Energy Demand Functions in Pool & Panel Data

Dependent variable (Per Capita log TFEC)	**Panel specification model**	
Independent variables	Pooled-OLS	Fixed Effect Model
Log price	-.1226296*** (.0268491)	-.102571*** (.0187127)
GDP per capita	.000207*** (5.92e-06)	.0001841*** (.0000102)
Square GDP per capita	-3.92e-09*** (1.69e-10)	-3.12e-09*** (2.27e-10)
Constant	-1.585865*** (.041862)	-1.54216*** (.0563268)
Derived GDP per capita maximizing/minimizing energy demand TFEC	-26,403 $↓	-29,503 $↓

Note: Hausman Test; Prob>chi2= 0.048
Thus, it reports only the fixed effect coefficients

Table 12.2b: Coefficient Estimates of Dynamic Energy Demand Function in Each country & Derived GDP per capita Maximizing Energy Demand

Dependent variable (Per capita Log TFEC)	Australia	China	Japan	S. Korea	Philippines	Singapore	Thailand	India
Log price	.0253392** (.008107)	.0665349** (.0324817)	-.056525** (.0176486)	.1057709** (.0436353)	-.0346337** (.0149685)	.0645889** (.0275114)	-.0498082* (.0247245)	-.0790377** (.0256327)
GDP per capita	.0001018*** (.0000102)	.0009243*** (.0001217)	-.0000402**	.0003368*** (.0000298)	.0044102** (.0018216)	.0001171*** (8.23e-06)	.0011645*** (.0000852)	.0020044** (.0006159

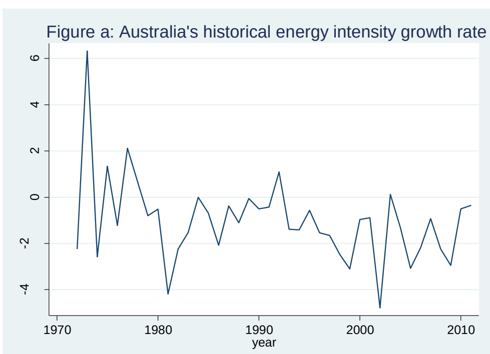
			(.000018)					)
Square GDP per capita	-1.58e-09*** (1.76e-10)	-1.53e-07** (3.70e-08)	1.04e-09*** (3.23e-10)	-9.67e-09*** (1.11e-09)	-1.86e-06** (7.74e-07)	-1.14e-09*** (2.14e-10)	-9.37e-08*** (2.19e-08)	-6.85e-07 (4.33e-07)
Constant	-.405849** (.1409007)	-1.39269*** (.0559878)	1.04472*** (.2297515)	-1.746956*** (.1544758)	-4.224989*** (1.055727)	-1.108587*** (.0538899)	-2.679416*** (.0538868)	-2.7926*** (.1819144)
Derived GDP per capita maximizing/minimizing per capita energy demand TFEC	-32,215 $↓	-3,020 $↓	+19,326 $↑	-17,414 $↓	-1,185 $↓	-51,359 $↓	-6,214 $↓	-1,463 $↓

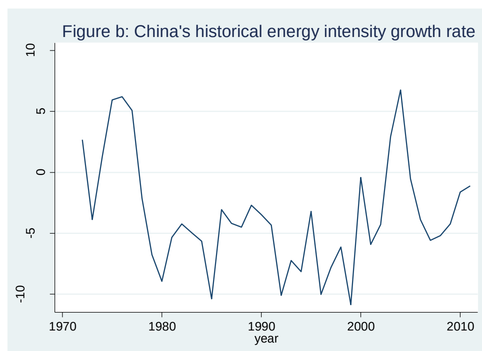
Table 12.2c: Short and Long-run associations of Energy Demand (TFEC) and its covariates using Vector Error Correction Model

Dependent variable (Δ per capita logTFEC)	Australia	China	Japan	S. Korea	Philippines	Singapore	Thailand	India
Correction term (δ)	-.2376164***	-.336133***	-.3147112**	-.1589532**	.1435722***	-.378682**	.2388997**	.216517**
	(.0656543)	(.1330021)	(.1547952)	(.0585031)	(.0554136)	(.1961135)	(.0874298)	(.0797304)
Per capita log TFEC								
Lag1 Δ	.0225666	.3821443**	.3104491	-.0622279	-.3980857*	.0969218	-.1447924	-.5283759*
	(.2324569)	(.1893587)	(.2145873)	(.1963943)	(.2389107)	(.2404678)	(.2828087)	(.2488979)
Lag2 Δ	-.1177618	.1253752	.2654904	-.0641782	.0242085	.6021337**	-.6440835**	-.1359827
	(.2279041)	(.2177242)	(.2219465)	(.2073006)	(.2064197)	(.305538)	(.2707831)	(.2049093)
Lag3 Δ	-.0384104	.0960854	.020561		.1493083	-.4100658*	-.3374121	
	(.2045538)	(.1856462)	(.1974148)		(.2096281)	(.2286869)	(.2980484)	
Log price								
Lag1 Δ	.0215382	.0010947	-.0130284	-.0251408	-.0621567	-.1173683	-.0664864**	.0057174
	(.0131803)	(.0289667)	(.0275418)	(.0296789)	(.0443538)	(.0732935)	(.0305541)	(.0166403)
Lag2 Δ	-.007512	-.0651841	-.0012958	-.0354396	-.0396367	-.0678363	-.0474603	-.002598
	(.012565)	(.026296)	(.0253862)	(.0289886)	(.0454122)	(.0632702)	(.0354006)	(.0156085)
Lag3 Δ	.0111533	.0086231	-.0014268		-.0151749	.0206424	-.0453874	
	(.0109963)	(.0316556)	(.020271)		(.0437731)	(.0602064)	(.0322574)	
GDP per capita								
Lag1 Δ	-1.16e-06	.0005154	-.0000107	8.87e-06	-.0008382	.0000739	.0007403	.0042536***
	(.000043)	(.0008917)	(.0000454)	(.0000835)	(.0031362)	(.0001112)	(.0007127)	(.0011979)
Lag2 Δ	-.0000261	-.001052	-.0001256	.0001815*	-.0043108	.0000244	.0015296*	.0001643

	(.0000422)	(.0013204)	(.0000441)	(.0001017)	(.0037343)	(.000138)	(.0008914)	(.001255)
Lag3 Δ	-9.75e-06	-.0003551	-7.37e-06		-.0120918**	-.0003954**	.0014227	
	(.0000395)	(.0009596)	(.0000664)		(.0045897)	(.0001691)	(.0012595)	
Square GDP per capita								
Lag1 Δ	8.72e-11	8.88e-08	-3.64e-11	3.68e-10	1.00e-06	-1.45e-09	-1.09e-07	-3.09e-06***
	(7.68e-10)	(2.47e-07)	(6.95e-10)	(2.82e-09)	(1.50e-06)	(2.02e-09)	(1.31e-07)	(8.68e-07)
Lag2 Δ	5.08e-10	2.35e-07	1.88e-09**	-7.52e-09*	2.23e-06	-9.99e-10	-2.19e-07	-2.08e-07
	(7.64e-10)	(3.47e-07)	(7.11e-10)	(3.56e-09)	(1.84e-06)	(2.70e-09)	(1.81e-07)	(1.04e-06)
Lag3 Δ	1.45e-10	3.30e-07	5.27e-11		5.97e-06**	7.77e-09**	-3.12e-07	
	(7.38e-10)	(2.75e-07)	(1.12e-09)		(2.35e-06)	(3.53e-09)	(2.66e-07)	
Constant	-.0190092*	-.0308262	-.0222377	.1239887	-.0154256	.3130021***	-.1759208**	.0028049
	(.0114793)	(.0228611)	(.0187129)	(.0315359)	(.0178409)	(.087743)	(.0775416)	(.0109608)

Figure 12.1 a-h: Historical Energy Intensity Year on Year growth rate in each of countries studied





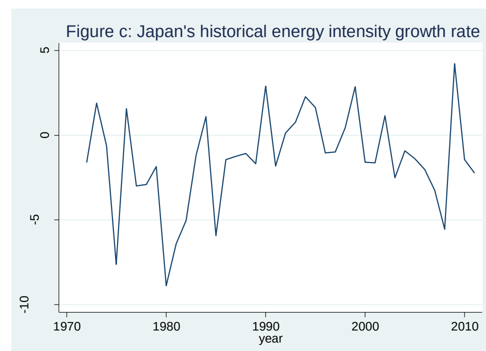


Figure d: South Korea's historical energy intensity growth rate

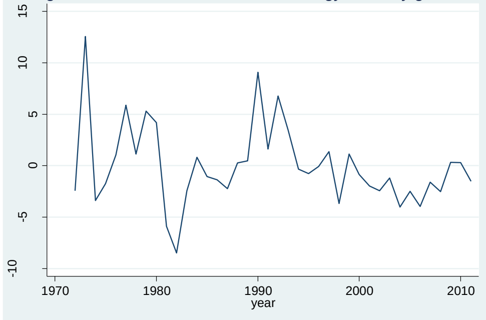


Figure e: Philippines' historical energy intensity growth rate

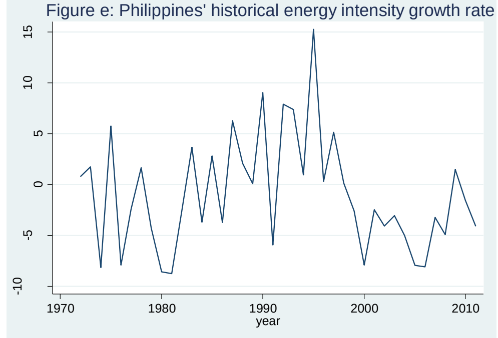


Figure f: Singapore's historical energy intensity growth rate

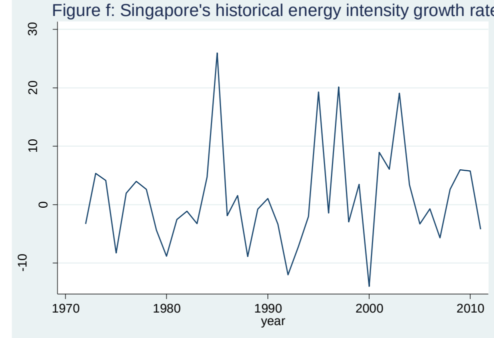


Figure g: Thailand's historical energy intensity growth rate

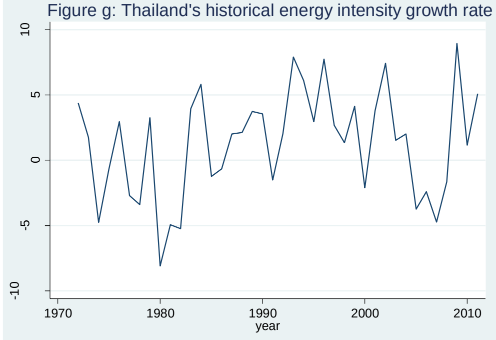
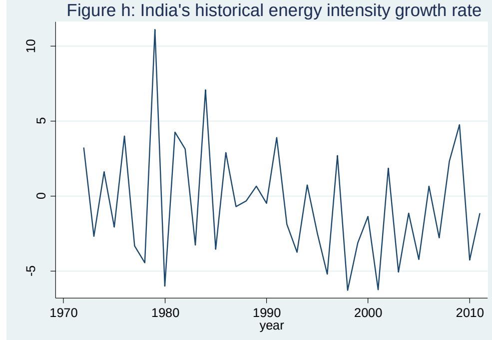


Figure h: India's historical energy intensity growth rate



Conclusions

As mentioned earlier, this study has been motivated by the recent shift of energy demand's gravity to Asia due to decades of robust and stable economic growth leading to the increasing energy demand in this region. The study has three objectives, namely: (i) to investigate non-monotonic relationship between energy intensity -- thus energy demand -- and income level in selected ASEAN and East Asia countries since many stakeholders, including policymakers, would like to know whether the energy intensity-thus energy demand-- is likely to fall as these countries become richer; (ii) to assess the short and long-run associations of energy demand with energy price and income level; and (iii) to assess the individual country performances in curbing energy intensity in order to ascertain whether the country is on the right track or whether it needs to revisit its overall policy to ensure that the right ones are in place.

The study shows that selected countries in ASEAN and East Asia as a group have moderately achieved 0.63 percent and 1.15 percent of energy intensity reduction during the periods 1971-2011 and 2000-2011, respectively. This energy intensity reduction rate is higher than the global average rate of 0.5 percent in the period 2000-2010. The slowdown in the global reduction rate of energy intensity could largely be attributed to the worsened performance of the energy intensity in some parts of the Middle East since the 1980s due to the low energy price that discouraged the deployment of energy efficient technologies (IEA, 2012).

ASEAN and East Asia as a group tends to have trade-off relationship between energy intensity-thus energy demand-- and income. However, each individual country in ASEAN and East Asia experiences the rise and fall of energy intensity. This is likely due to the shift in structure of the economies as some countries may move gradually from agriculture to industry-based economies while others may move from industry to service-based economies. All countries studied experience the reduced energy intensity, except for few ASEAN countries, where the increase of energy intensity may be due to data problem since this study uses IEA data in which Naphtha were included in the energy balance table.

Both per capita energy consumption and income have grown for all countries which implies the close relationship between energy demand and income growth. However, this study found that as income increases, per capita energy demand will reach a level of saturation which pushes the fall of energy demand. The study found that Australia, China, South Korea and the Philippines have already experienced the decline of per capita energy demand when per capita income have reached US$ 32,215 for Australia, US$ 3,020 for China, US$ 17,414 for South Korea, and US$ 1,185 for the Philippines. Meanwhile, countries like Singapore, Thailand and India have yet to experience the decline of the per capita energy consumption. Japan seems to have experienced the decline of per capita energy demand at the early stage of its development when per capita income was less than US$ 19,326. However, when this threshold is exceeded, Japan is likely to increase the per capita energy demand again.

This study's Error Correction Model in each country shows that energy intensity -- thus energy demand -- has both short and long-run associations with energy price and income. This is important to confirm for the theory of energy demand and to ensure that this study's model specifications of non-monotonic function of energy demand have both short and long-run associations with price and income. In this case, both price and income have induced the speed of adjustment towards long run equilibriums to jointly granger cause the energy intensity and energy demand.

Policy Implications

(a) By examining individual country's energy intensity, energy intensity-thus energy demand- declined at the initial stage where per capita income stayed below certain thresholds, but as income continues to rise above the thresholds, the energy intensity in some countries starts to rise again. ***These findings imply that it does not matter what level of per capita income a country has; as long as the country has the right policies in place, it can reduce energy intensity. Therefore, it is very important for each country to revisit its energy efficiency policies in***

different sectors to ensure that any structural changes in the economy will maintain the energy efficiency as core to its policy.

(b) The study found that Australia, China, Japan, South Korea, and the Philippines have generally done well in terms of curbing the energy intensity. However, few countries may need to speed up policies to reduce the energy intensity so that in the long run, it could bring in the negative growth of energy intensity. ***These findings imply that aggressive energy efficiency policies will need to be considered for countries with positive energy intensity.***

(c) The study's models show that energy intensity -- thus energy demand -- has both short and long-run associations with energy price and income. In this case, both price and income have induced the speed of adjustment towards a long run equilibrium to jointly granger cause the energy intensity and energy demand. ***These findings imply that energy intensity -- thus energy demand -- has a trade-off relationship with income level which contributes to the theory of energy demand.***

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Annex

Table 12.A1. Johansen Test for Cointegration

Sample: 1975 - 2011

Country	maximum rank	parms	LL	eigenvalue	trace statistic	5% critical value
Australia	0	52	-757.55603	.	49.1920	47.21
	1	59	-745.89196	0.46767	25.8639*	29.68
	2	64	-739.03545	0.30970	12.1509	15.41
	3	67	-734.34457	0.22397	2.7691	3.76
	4	68	-732.96002	0.07211		
China	0	52	-499.14894	.	59.7196	47.21
	1	59	-484.02838	0.55839	29.4785*	29.68
	2	64	-474.93792	0.38822	11.2976	15.41
	3	67	-469.58091	0.25141	0.5836	3.76
	4	68	-469.28912	0.01565		
Japan	0	52	-800.19573	.	74.9123	47.21
	1	59	-783.25648	0.59974	41.0339	29.68
	2	64	-769.84806	0.51557	14.2170*	15.41
	3	67	-763.17226	0.30292	0.8654	3.76
	4	68	-762.73955	0.02312		
South Korea	0	52	-767.58344	.	60.9483	47.21
	1	59	-752.56011	0.55606	30.9017	29.68
	2	64	-741.73285	0.44304	9.2472*	15.41
	3	67	-737.60096	0.20016	0.9834	3.76
	4	68	-737.10927	0.02623		
Philippines	0	52	-464.99959	.	63.1600	47.21
	1	59	-444.48581	0.67006	22.1324*	29.68
	2	64	-437.35594	0.31982	7.8727	15.41
	3	67	-433.60224	0.18364	0.3653	3.76
	4	68	-433.41961	0.00982		
Singapore	0	52	-868.26379	.	36.9137*	47.21
	1	59	-857.84401	0.43063	16.0742	29.68
	2	64	-853.94698	0.18994	8.2801	15.41
	3	67	-850.12063	0.18684	0.6274	3.76
	4	68	-849.80692	0.01681		
Thailand	0	52	-587.28841	.	63.5717	47.21
	1	59	-568.58052	0.63623	26.1559*	29.68
	2	64	-560.02063	0.37042	9.0361	15.41
	3	67	-556.45672	0.17522	1.9083	3.76
	4	68	-555.50256	0.05027		
India	0	52	-410.41893	.	71.8300	47.21
	1	59	-393.47337	0.59987	37.9389	29.68
	2	64	-382.15707	0.45757	15.3063*	15.41
	3	67	-375.66709	0.29588	2.3263	3.76
	4	68	-374.50394	0.06094		

CHAPTER 13
Impact of International Oil Price Shocks on Consumption Expenditures in ASEAN and East Asia

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This paper examines the impact of international oil shocks on consumption expenditure in selected ASEAN and East Asia economies. By including oil shocks into a standard macroeconomic model of consumption theory, one sees the response of consumption to the changes in the international oil price. Empirical results show that oil shocks do affect consumption and there are asymmetrical effects. There are clear differences in the level and direction of the impacts on each of the ASEAN and East Asia economies. These implications shed light on how the idea of regional energy market integration can be a way to share risks and optimise resource allocation. Nonetheless, given the clear disparity and similarity in sub-groups, integration should be implemented while allowing for differentiation in terms of the role each country plays.

Keywords: Oil shocks; Consumption expenditure; Permanent Income Hypothesis; ASEAN/East Asia; Energy market integration.
JEL: Q4, G12, G14

Introduction

The fast economic growth within the Association of South East Asian Nations (ASEAN) and surrounding East Asian countries such as China, during the last decade has created an enormous demand for energy, generating unprecedented pressures on regional energy supply chains. Among the primary energy sources, oil has the largest share in the regional energy consumption mix, and this is likely to remain so for several decades to come (Lu, *et al*., 2012).

In the East Asia region, four countries are currently in the list of the world's top 10 oil importers: These are China, Japan, South Korea, and Singapore (The CIA World Fact Book, 2012). Growing supply gaps increase these countries' dependence upon international energy markets and further expose them to international risk, in addition to those in the domestic market. Likewise, many countries in this area have started to deregulate their energy market and to make domestic prices more flexible to international shocks. This deregulation also increases their exposure to the risks in the international energy market. The price of international oil, therefore, is very likely to have significant impact upon economic activities within this region.

Scholars have long been paying attention to how oil shocks influence changes in economic activities. In one of the earliest works, Hamilton (1983) established a basic framework for studying the broad relationship between oil shocks and economic recession (sustained periods of negative GDP growth) in the United States.

Ever since Hamilton's early work, the real impact of international oil shocks has been studied intensively. However, the vast majority of these studies focus on the impact from the perspective of either economic growth (output) or the financial sector. Mehra and Peterson (2005) were among the first to explicitly investigate the impact of international oil shocks on the residential sector's consumption expenditure (i.e., to check how oil shocks may impact the consumer side of the economy).

Consumption expenditure (specifically, the consumption of domestically produced goods and services) has been an important contributor to economic development in the ASEAN and East Asian countries, especially since the 2008 global financial crisis that caused global demand for exported goods to decline. According to the Asia-Pacific Trade and Investment Report (2011), most ASEAN and East Asian economies' year-on-year growth in exports experienced a dramatic drop in the fourth quarter of 2008 and remained negative in the year 2009. Although it rebounded in 2010, the growth rate for almost all of the countries in this region slowed down steadily.

When the purchasing power of the advanced Western economies shrinks due to a crisis, it is necessary for the ASEAN and East Asian economies to resort to alternative drivers for their own economy. Among other things, this scenario has historically also resulted in lower levels of government expenditure as a precautionary measure, which again has an impact on the domestic growth's potential. As a result, there has been more emphasis on fostering domestic growth, as can be seen from the case of China:

"*China is now at such a crucial stage that without structural transformation and upgrading, we will not be able to achieve a sustained economic growth. In readjusting the structure, the most important aspect is to expand domestic demand…*"– The Chinese Prime Minister, Keqiang Li (2013)[1]

The statement above sends a clear message that boosting domestic consumption is crucial to Chinese economic development. While this is perhaps most pertinent to China given its dominant role in the global export market, other economies adopt a similar aspiration. Given (1) a stated desire to restructure (at least some) regional growth models so as to place a greater emphasis on domestic consumption expenditure; (2) the heavy oil-importing structure of the regional economies; and (3) other regions' experience with how oil shocks had potentially significant and multiple effects on their economic performance, it is therefore of great interest to empirically assess whether domestic consumption expenditures react to international oil shocks.

The policy relevance of this multi-country/market study also lies in the fact that there is an increasing desire/appetite for wider economic integration in this region. Closer linkages between the ASEAN and East Asian economies

[1]The address to the Summer Davos opening ceremony, September 11, 2013.

make deeper cooperation possible in all areas. The idea of an energy market integration (EMI) in this region has been intensely discussed in recent years owing to the comprehensive and compelling views put forward by Shi and Kimura (2010). That is, these dialogues tackled how EMI can potentially be helpful in terms of broader risk sharing (i.e., resilience against international energy market movements) and optimizing resource allocation.

The local/regional cooperation in the electricity market and other areas such as renewables development has already proven that multi-lateral cooperation on energy matters is feasible. Better risk sharing and optimizing resource allocation may further complement plans to smooth out the consumption trajectory in this region, which is also crucial for reducing regional economic volatility.

In tackling EMI, policymakers have to recognise the heterogeneity within the region both in terms of the level of economic development and economic structure. While integration may bring overall benefits to this region, it is necessary to consider how to balance the unequal energy resource endowments across the region, which are particularly obvious with respect to oil. The region consists of many countries dependent on imported oil (and thus subject to the shocks from the international oil market) on one hand, as well as oil-exporting nations with large regional reserves on the other hand. Thus, whether existing understandings of EMI carry over to the oil markets for the consumption side of the economy (as opposed to the production side) remains a valid question.

In this sense, measuring how economies in this region respond to the international oil shock through a time series framework can help one understand how EMI impacts regional economic development.

This paper looks into how international oil shocks impact consumption expenditure in nine ASEAN and East Asia economies. Thus, a widely used macroeconomic specification for modelling consumption expenditure (based on a permanent income hypothesis---PIH in short) is adopted, and differences between actual and planned consumption are quantified by using an error correction model (ECM) augmented to account for oil shocks. In its empirical model---which follows closely that of Mehra and Peterson (2005)--oil shocks are a transitory phenomenon and do not affect the long-run level of consumption expenditure.

Following, for example, the Broadstock *et al*. (2014) study, this paper argues that oil price shocks can transmit to consumption expenditure through both a direct and an indirect channel. Traveling in either a car[2] or riding a bus as a passenger creates a demand for oil, and is therefore an example of a direct effect. A hike in the price of oil and, in turn, oil-related products, will increase transportation costs and alter the consumption for goods that directly involve transport.

The indirect channel, on the other hand, may manifest in one of two ways. The first indirect effect may come through inflationary concerns and general income effects. The general idea is that rising oil prices lead to overall price inflation (Bernanke *et al*., 1997), which can trigger the monetary authority to respond with contractionary measures. This can sometimes cause further depression in the economy. In such circumstances, consumption would be negatively affected, too. The second source of indirect effect manifests as a substitution effect resulting from a rise in the price of oil.

In this study, the PIH-based empirical model of consumption expenditure is applied separately to a sample of nine economies from the region: China, Hong Kong, Indonesia, Japan, Malaysia, Singapore, South Korea, Taiwan, and Thailand. Within this group, four are from the ASEAN and five are from East Asian. While the countries were ultimately chosen on the basis of data availability, they nonetheless reflect the varied geographical, economic and social development levels across the region (i.e., different levels of economic development, physical scales and political systems, and also a mixture of oil producing, importing and exporting nations). The analysis in this paper, therefore, is in principle able to provide insights relevant to all regional members, even those not directly represented in its data.

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[2] The number of cars in the private sector has risen significantly over the last couple of decades. For example, the rates of private car ownership in China increased more than 30-fold, from 0.6 cars per 100 urban households in 2000 to 18.28 in 2011. At the same time, the consumption of oil used for transportation doubled between 2000 and 2010 due to the high speed of urbanisation. Similar patterns can also be seen in other economies in this study, making oil shocks more relevant to private consumption.

The order of the paper is as follows: The next section briefly reviews relevant literature. Section 3 then describes the empirical methodology and research design. Section 4 discusses the data used for analysis. Results, along with some policy implications, are then presented and discussed in Section 5, after which the paper concludes in Section 6.

Literature Review

The review in this section begins with a brief overview of the wider literature, many of which are on how oil shocks affect either total economic growth or financial market performance. However, existing literature on consumption expenditure is much sparser. This section, therefore, also provides summaries of studies on consumption expenditure.

The influence of international oil shocks upon overall macroeconomic performance has been well expounded in literature. After Hamilton's study (1983), which found a significant negative relationship between oil shock and economic growth, there have been many others adopting various time series methodologies, confirming their linkages in most, if not all, geographical contexts (see for example: Mork, 1989; Lee, Ni and Ratti, 1995; Hamilton, 2003; Zhang, 2008). The underlying premise is that rising oil prices pass through the economy as an increase in production costs, resulting in price inflation, which eventually creates wage inflation, coupled with reduced demand due to rising costs. The general consensus is that oil shocks are largely negative to an economy. Benanke, *et al*. (1997), for example, argue that inflationary pressure generated from oil price hikes triggers the Fed to respond with contractionary a monetary policy, which eventually causes further depression in the economy.

Studies on the impact of oil shocks on household consumption expenditure have just recently been a focus of study, and only by a handful of directly related papers such as those of Mehra and Petersen (2005), Odusami (2010), and Wang (2013).[3] Consumption expenditure is modelled in these papers using the permanent income hypothesis (PIH) framework that originated from Friedman (1956) and has become the "workhorse" for macroeconomists wishing to describe consumption expenditure either theoretically or empirically.

The simplest description of the PIH is that consumption is affected by the current level of income and wealth plus the expected value (discounted) of all future streams of income. That is, consumption choices are influenced by a permanent or lifetime expectation of income that is less likely to change from one year to the next. In a "perfect world", consumption expenditure will be determined by an optimal or equilibrium relationship with permanent income. In reality, however, any month/quarter/year is influenced by unexpected events that cause consumption expenditure to deviate from its optimal or, in the terminology of Campbell and Mankiw (1989) or Mehra and Peterson (2005), its "planned" level. Error correction models are therefore used to jointly model the long-run equilibrium level of consumption based on income and wealth, while at the same time measuring deviation from the equilibrium (planned) level of consumption. Mehra and Peterson (2005) specify the role of oil shocks in household consumption as a source of short-run deviation that does not fundamentally alter the planned consumption level, but rather acts as a determinant of short-run consumption behaviour.

Odusami (2010) makes some interesting departures in methodology from Mehra and Peterson (2005). Odusami (2010) agrees that consumption is somehow affected by oil shocks. However, instead of incorporating oil price movements into a consumption function directly, it is argued that they generate certain "rebalancing" effects that transpire as a change in the consumption-to-wealth ratio. Another paper taking yet another methodological approach is Edelstein and Kilian's (2009), which uses vector-auto regressions (VAR) and their associated historical decompositions to identify how different consumption categories respond to changes in purchasing power induced specifically by oil shocks. Among other things, Edelstein and Kilian (2009) demonstrate the existence of the "reallocation"

[3] While there have been, over the years, a number of studies developing structural models of the economy, their general equilibrium setups often require questionable or even unrealistic assumptions to make the system fully identified. This may in part explain why more recent work is comfortable adopting the partial equilibrium analysis.

effect, which states that households re-evaluate their consumption choices when faced by a new bundle of prices (due to the oil price change). Additionally, they argue that a 1-percent increase in the price of oil would lead to a net reduction of consumption expenditure of 0.15-percent a year later.

This paper's research follows most closely the methodology of Mehra and Petersen (2005), which will be presented in detail in the next section. While the frameworks of Edelstein and Kilian (2009) and Odusami (2010) both have merit, they are not applied here. Data limitations ultimately exclude Edelstain and Kilian (2009)'s VAR-based approach as a possibility. Meanwhile, Odusami's (2010) study allows oil shocks to determine the consumption-to-wealth ratio, therefore implicitly assuming that oil shocks can disrupt optimal consumption expenditure levels.

This paper prefers the assumptions in Mehra and Peterson (2005), which are more consistent with the idea that households, when faced by a rise in oil prices, may reallocate their consumption patterns (creating short run dis-equilibrium while the new preferred consumption bundle is "found"), but will continue to spend the same amount of money in the long run.

Methodology and Research Design

The methodological approach used here closely follows that of Mehra and Peterson (2005).[4] The empirical framework begins with a general/standard macroeconomic specification of (per-capita) household consumption, where the level of consumption in an economy, C_t, is affected by the existing level of wealth, W_t, as well as current and discounted expected future income, Y_t and $E(Y_{t+1})$, respectively, where $i = 1,...,\infty$. In this regard, the approach embeds the commonly used PIH, which has been used recently (for example, by Palumbo *et al.*, 2006) to describe consumption by the household sector. Defining consumption, income, wealth, and the interest rate in real terms as C_t, Y_t, W_t, and r_t, respectively, the household budget constraint can be written

[4] The general framework is an extension of an earlier study by Mehra (2001) but is extended here to include oil shocks.

as:

$$W_{t+1} = (1+r_t)(W_t + Y_t - C_t), \qquad (1)$$

such that next-period wealth equals the discounted value of current-period wealth plus earned income minus any consumption expenditure. Assuming a constant real interest rate $(r_t = r_{t+1} = r)$ and imposing the condition that $\lim_{i\to\infty}\left(W_{t+i} / (1+r)^i\right) = 0$, then, by repeated substitution of the budget constraint, current-period wealth is obtained as:

$$W_t = \sum_{i=0}^{\infty} \frac{C_{t+i}}{(1+r)^i} - \sum_{i=0}^{\infty} \frac{Y_{t+i}}{(1+r)^i}. \qquad (2)$$

Result from Hall (1978), where consumption follows a martingale process, gives $E(C_{t+1}) = C_t$. Then, taking the expectations of equation (2) results in the common form of the PIH:

$$C_t = \frac{r}{1+r} \sum_{i=0}^{\infty} \frac{E\left(Y_{t+i}\right)}{(1+r)^i} + \frac{r}{1+r} W_t. \qquad (3)$$

Assuming a constant growth rate of real income, g, then $E(Y_{t+1}) = (1+g)Y_t + \eta_{t+1}$, where η_{t+1} is a white noise process. Thus:

$$C_t = \frac{r}{r\text{-}g} Y_t + \frac{r}{1+r} W_t + \sum_{i=1}^{\infty} \frac{\eta_{t+1}}{(1+r)^i}. \qquad (4)$$

The derivation to this point establishes that a long-run relationship exists between consumption, income, and wealth. Mehra and Peterson (2005) refer to this as the planned level of consumption, C_t^p, expressing it in a simpler form by first taking expectations of the error term and adding a constant term, leading to the estimable long-run relationship

$$C_t^p = a_0 + a_1 Y_t + a_2 W_t, \qquad (5)$$

where $a_1 = \dfrac{r}{r-g}$ and $a_2 = \dfrac{r}{1+r}$. Actual consumption, however, differs from planned consumption for a multitude of reasons. Campbell and Mankiw (1989) show that the short-run dynamics of consumption can be conveniently written in the form of an error correction model:

$$\Delta C_t = b_0 + b_1\left(C_{t-1}^p - C_{t-1}\right) + b_2 \Delta C_{t-1}^p + \sum_{s=1}^{k} b_{3s} \Delta C_{t-s} + \mu_t. \qquad (6)$$

Substituting equation (5) into (6),

$$\Delta C_t = b_0 + b_1\left(a_0 + a_1 Y_{t-1} + a_2 W_{t-1} - C_{t-1}\right) + b_2 \Delta\left(a_0 + a_1 Y_{t-1} + a_2 W_{t-1}\right) + \sum_{s=1}^{k} b_{3s} \Delta C_{t-s} + \mu_t. \qquad (7)$$

Assuming that future income grows constantly relative to the current level, and that consumers have rational expectations, the expected value of accumulated and discounted future income streams is proportional to the current income. The model can be simplified to:

$$\Delta C_t = \beta_0 + \beta_1\left(C_{t-1}^{p} - C_{t-1}\right) + \beta_2 \Delta Y_{t-1} + \beta_3 \Delta W_{t-1} + \sum_{s=1}^{k} \beta_{4s} \Delta C_{t-s} + \mu_t . \qquad (8)$$

Equation (8) is the baseline model used in the analysis to capture the dynamics of consumption changes. Following Mehra and Peterson (2005), oil prices are augmented into the short-run equation

$$\Delta C_t = \beta_0 + \beta_1\left(C_{t-1}^{p} - C_{t-1}\right) + \beta_2 \Delta Y_{t-1} + \beta_3 \Delta W_{t-1} + \sum_{s=1}^{k} \beta_{4s} \Delta C_{t-s} + \sum_{s=1}^{k} \beta_{5s} \Delta oil_{t-s} + \mu_t . \qquad (9)$$

Equations (5) and (9) establish the main equation for the empirical analysis.

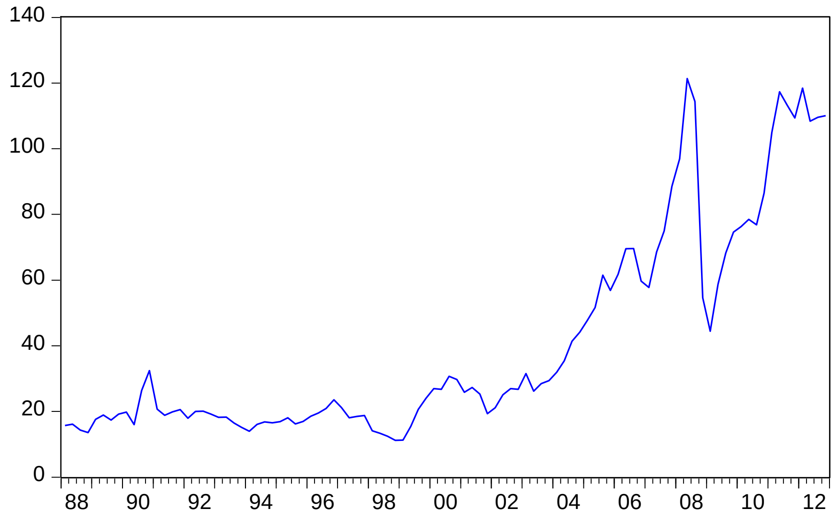
Data

As mentioned earlier, this paper's empirical study covers nine countries: China, Indonesia, Japan, Malaysia, Singapore, South Korea, Taiwan, Thailand, and Hong Kong. Quarterly frequency data on consumption, income, and wealth[5] ranging from 1988Q1 to 2012Q4 are obtained from DATASTREAM. Oil price data are taken from the US Energy Information Administration (EIA), and based on European Brent prices since Brent accounts for around 60 percent of international oil trade[6] (see, for example, Odusami [2010, p. 860] for further discussions on this). The oil price data are shown in Figure 13.1, which highlights among other things, the significant variation in international prices over the sample period. In particular, note the tremendous surge in prices after 2000, and the subsequent collapse in 2008.

[5] Wealth is the end-of-quarter per-capita net worth in the household sector (see DATASTREAM's definition).

[6] Other relevant oil prices (i.e., Daqing, Dubai, Cinta, and Minas) were also compared with Brent. They are highly correlated and follow almost identical trends.

Figure 13.1: Brent oil price (in US dollars)



All consumption, wealth, and income data are denominated in local currency, and X12 is used to perform seasonal adjustment. The series are all deflated into real terms using the domestic GDP deflator. For the estimation, natural logarithms are taken for each of the series. Oil prices are converted to the local currency to mitigate any exchange rate-related effects, and are also scaled by the GDP deflator into real terms relevant to the domestic economy.[7]

Empirical Results

This section presents and provides some initial explanation on the empirical results. Before going into the details, it is useful to first prove that the error correction model (ECM) output is a (statistically) valid approach to the data, based on the time series properties of the data.

To help validate the ECM application, it is thus useful to conform to the stationarity properties of consumption, income, and wealth. A first condition for the ECM to be "valid" is that the individual series must first be integrated

[7] This study acknowledges the possibility that exchange rate movements can impact consumption since there are many exports in this region. However, consistent with the body of literature reviewed in this paper, such is not considered further here, although this is an area where further research is justified.

of the first order, denoted as I(1) or non-stationary, which implies that the data are trending. After taking the first differences, the trend component is eliminated and can be denoted as I(0) or stationary. An augmented Dickey-Fuller test (ADF) is used to determine whether each series is stationary or not, with the results reported in Table 13.1. It is clear that these series are each I(1) process (except all variables for Japan, which are marginally stationary around a constant and time trend, and the income variable for Malaysia). In general, these test results indicate that an ECM-type process---and hence the planned consumption framework---may be reasonable.

Table 13.1: Unit Root Tests for Variables Entering into the Long-Run Consumption Function

Series:	**Consumption**		**Income**		**Wealth**	
Country	**ADF level**	**ADF difference**	**ADF level**	**ADF difference**	**ADF level**	**ADF difference**
CHN	-2.2772	-11.8583**	-2.1367	-7.2622**	-2.2427	-6.1429**
HK	-2.0011	-7.2446**	-1.7805	-6.2573**	-2.5952	-7.1837**
JPN	-3.3841*	-11.3645**	-3.7411*	-14.5814**	-3.3050*	-5.5643**
SIN	-2.8136	-7.3607**	-2.8667	-8.5545**	-2.3826	-7.3174**
MAL	-3.1281	-10.4676**	-3.8936*	-6.3655**		
IND	-2.3077	-11.9654**	-1.5151	-8.4556**		
THAI	-3.0902	-8.0644**	-2.7742	-9.5302**		
TW	-2.2113	-9.7606**	-2.8381	-9.2934**		
SK	-2.2315	-6.6824**	-2.5851	-6.1092**		

Note: lag orders are for the test are selected using SIC, as is the inclusion of a deterministic trend. Stars are used to denote significance as follows: ** for 1-percent level of significance and * for 5 percent.

Wealth data for the whole sample period are only available for China, Japan, Hong Kong and Singapore; other regions either do not have wealth data or have only very short series available---too short for robust or consistent comparison. For regions with wealth data available, all three variables (wealth, income, and consumption) are used to establish the equilibrium.

The Estimated Consumption Function and Evidence of a "Statistical" Equilibrium

Testing the validity of the planned consumption framework and the PIH is not the primary interest of this study. Nonetheless, it is important to confirm as far as practicable that this framework applies readily to the data in the selected sample. A second condition that must be satisfied for an ECM to be valued is that the residuals from estimating Equation (5) are themselves I(0) or stationary. Table 13.2 gives the results of both ADF and KPSS (Kwiatkowski *et al*. 1992) tests. The KPSS is generally preferred on theoretical grounds. It is also considered since Thailand and South Korea seem to fail on the simpler ADF test. For these latter two countries, the KPSS test still supports stationarity and justifies proceeding to estimate the short run ECMs in Equation (4).

Cumulatively, the results in Tables 13.1 and 13.2 support the existence of error correction. Strictly speaking, the results do not prove the planned consumption approach to be valid, but there is certainly strong evidence that the planned consumption framework has significant merit for the countries/sample period under investigation.

Table 13.2: Residual Based Co-Integration Tests for Sample-Countries

Residuals for	ADF test	KPSS test
CHN	-3.9112*	0.0560
HK	-4.4742**	0.0359
JPN	-7.2549**	0.0586
SIN	-4.2143*	0.0455
MAL	-5.3767**	0.0345
IND	-4.7471**	0.0781
THAI	-3.2905	0.0760
TW	-3.4807*	0.0610
SK	-3.3522	0.0543

Note: Critical values for ADF test on co-integration is taken from MacKinnon (1991). The KPSS test on co-integration is taken from Shin (1994). Stars are used to denote significance as follows: ** for 1-percent level of significance and * for 5 percent.

The ECM results reported below in Table 13.3 and their interpretation have several important aspects. Before discussing the role of international energy prices, it is useful to understand the general behaviour/performance of the income and wealth components of the models to ensure that they are (at least reasonably) consistent with expectations. In this regard, the first areas to look at are the standard components of the consumption function; namely, the wealth, income, lagged consumption, and error correction effects. This is discussed briefly in the next section before moving on to the role of international oil shocks in each of the studied countries.

Table 13.3: ECM Regression Results for Asymmetric Oil Shocks

	China	Hong Kong	Japan	Singapore	Indonesia	Malaysia	South Korea	Taiwan	Thailand
Intercept	2.614**	0.841**	0.468*	1.305**	1.747**	1.147	0.531	1.406**	0.865
p-value	0	0.001	0.04	0.001	0.008	0.115	0.354	0	0.174
ect_1	-31.287**	-22.027**	-54.637**	-6.279	-16.158	-15.664*	-10.229*	1.021	-4.224
p-value	0.001	0.001	0	0.356	0.142	0.034	0.023	0.953	0.356
inc_1	-0.091	0.072	-0.144	-0.293*	0.043	0.36*	0.423	0.63	0.034
p-value	0.497	0.13	0.197	0.048	0.8	0.037	0.535	0.13	0.811
wea_1	-0.064	0.028	-0.142	0.021					
p-value	0.656	0.584	0.121	0.749					
con_1	-0.122	0.227	0.039	0.491*	-0.125	-0.098	0.233	-0.731	0.175
p-value	0.381	0.054	0.684	0.012	0.322	0.322	0.399	0.087	0.478
oil_neg_1	-0.004	-0.009	0.016	0.052*	-0.011	0.036	-0.011	0.013	0.036*
p-value	0.834	0.633	0.262	0.041	0.487	0.136	0.446	0.455	0.03
oil_neg_2	-0.011	-0.045*	-0.022**	-0.007	-0.023	-0.006	-0.039**	-0.048**	-0.007
p-value	0.427	0.022	0.001	0.691	0.394	0.72	0.01	0	0.684
oil_neg_3	0.018	0.021	0.003	-0.006	-0.011	0.061*	0.01	-0.008	-0.011
p-value	0.375	0.145	0.655	0.606	0.677	0.024	0.511	0.431	0.545
oil_neg_4	-0.041	0	-0.005	0.015	0.082*	0.054	0.002	-0.025	-0.023
p-value	0.292	0.987	0.334	0.218	0.035	0.241	0.823	0.074	0.186
oil_pos_1	-0.007	-0.051	0.01	-0.01	-0.05	0.001	0.016	0.001	0.01
p-value	0.698	0.008	0.289	0.649	0.316	0.954	0.359	0.916	0.698
oil_pos_2	-0.001	0.032	-0.002	0.013	0.042	0.09**	0.012	-0.004	-0.026
p-value	0.961	0.114	0.839	0.446	0.271	0.009	0.65	0.816	0.144
oil_pos_3	-0.037*	-0.015	0.026	0.025	0.03	0.015	-0.011	0.009	0.018
p-value	0.022	0.395	0.086	0.376	0.371	0.658	0.483	0.67	0.394
oil_pos_4	0.009	-0.015	-0.026	-0.029	-0.049	0.015	-0.042*	-0.046	-0.007
p-value	0.564	0.384	0.069	0.14	0.089	0.693	0.033	0.062	0.677
Log.lik.	-211.204	-187.46	-123.12	-195.221	-270.79	-238.73	-198.02	-179.77	-204.63

Note: Inference is based on heteroscedasticity and auto-correlation corrected standard errors. Stars are used to denote significance as follows: ** for 1-percent level of significance and * for 5 percent. Structural breaks were tested for using a Quant-Andrews test procedure, but not found to be significant and hence not reported.

Wealth, Income, Lagged Consumption and Error Correction

The "standard" components of the consumption function are wealth and income, mediated in the short- and long-run via lagged consumption effects and error correction terms.

As earlier mentioned, the wealth component can only be modelled for four out of the five regions owing to data limitations. Results are available for China, Hong Kong, Japan, and Singapore. For each of these, the result is the same. That is, that the wealth component is statistically insignificant (Table 13.3).

Since the estimated equations explain the short-run effects, it can then be concluded that changes in wealth do not generate an immediate short-run change in the level of consumption by the residential sector. Although no clear conclusion can be drawn for the remaining five regions, it seems likely that similar results might exist---i.e., that wealth is not a short-run determinant of residential consumption. This does not rule out the possibility of a long-run relationship.

This finding differs from the study of Mehra and Peterson (2005), which show a positive wealth effect for the US data. The difference may, in part, be explained by the generally different stages of economic development, where the Asia region is still generally catching up with the US. Also, different social and political structures may underpin different attitudes towards the treatment of wealth in consumption choices.

As to the effect of income, results are quite mixed across the nine regions. Some of the more major/developed economies such as China, Hong Kong, and Japan as well as some of the smaller economies that include Taiwan and Thailand, have no short-run reaction to changes in income. On the other hand, Indonesia, Malaysia, and South Korea all see a short-run increase in consumption as a result of a change in the level of income. Perhaps most interesting is Singapore's case, where the relationship between income and residential consumption in the short-run is negative. What mechanism justifies rising incomes to result in lower consumption expenditure? One likely answer lies in the partial scope of this study's analysis, where only the consumption of non-durable items was considered and therefore, the effect on durable items or even savings/investments cannot be ascertained. It is possible that rising incomes lead to a substitution across consumption categories beyond those classified in this study's data.

Lagged consumption is an important variable since it embeds within it additional routes for income and wealth effects to emerge. This is easily seen by noting from Equation (5) that:

$$C_{t-1}^{p} = a_0 + a_1 Y_{t-1} + a_2 W_{t-1} \qquad (10)$$

Therefore, when the coefficient on the lagged term is significant, the lagged income and wealth effects may possibility be transmitted to short-run consumption. The lagged terms are significant for Hong Kong, Singapore, and Taiwan. For Hong Kong and Taiwan in particular, the existence of some long-run income effect is implied by the auto-regressive lagged consumption term (while noting again that wealth information is not available for Taiwan). Indonesia and Thailand show no sign of a stable long-run relationship of any type, since neither the error correction term nor the auto-regressive term (the lagged consumption) is significant. These two countries are smaller and, in relative terms, have lower levels of political and economic development/stability than the other regions studied. Given the relatively short study window, it is perhaps not entirely surprising that a stable result cannot be found.

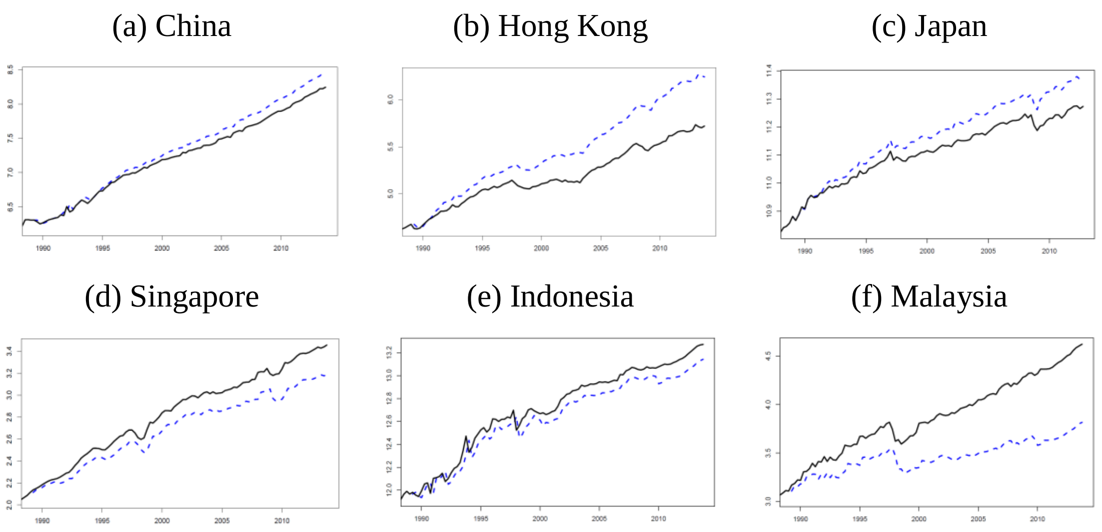
Error correction---i.e., a significant adjustment from actual consumption to some equilibrium level of planned consumption---is seen in China, Hong Kong, Japan, Malaysia, and South Korea. If one was willing to accept a loose 15-percent significance level, then Indonesia is also error correcting. For Singapore, Taiwan, and Thailand, error correction---and hence significant dis-equilibrium adjustment---is not a feature of the sample data. As mentioned above, these cases are not considered evidence that the theory itself is invalid. The theory simply does not hold strongly enough within the narrow sample period.

Oil shocks, which are entered into the model with up to four lags, are seen to be significant in all countries. However, there are some notable differences in how they affect each of the counties. China is only affected by positive price shocks, while Thailand, Taiwan, and Singapore are only impacted by negative shocks. Hong Kong, Japan, Indonesia, Malaysia, and South Korea feel the impact from both price rises and falls. Reactions to both negative and positive price shocks can be either positive or negative.

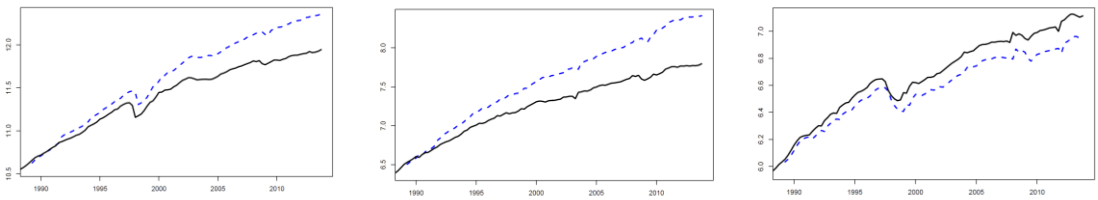
A Simple Counter-Factual Assessment of the Impact of International Oil Shocks

While important, the results in Table 13.3 require a certain amount of effort to discern and interpret. To this end, Figure 13.2 summarises the empirical implications of the results much more directly by providing a simple counter-factual simulation of what household consumption may have been if international oil shocks had not occurred (i.e., if international prices remained fixed at the real 1989Q2 price; hence, nominal prices would change directly in line with domestic inflation). Other scenarios are of course possible, but this one serves as an illuminating benchmark to the net consequence of oil shocks on each of the economies. This is done by taking the cumulative values of the short-run fitted equation (Equation 9), and calculating the resulting level of consumption expenditure when (1) the oil shocks are as observed in the real data; and (2) when the oil shocks are set to zero (i.e., international oil prices are held fixed in real terms at the 1988Q1 level).

Figure 13.2: Counter-factual Assessment of Consumption Expenditure in the Absence of International Oil Shocks



(g) South Korea (h) Taiwan (i) Thailand



Note: Solid (black) lines denote actual consumption expenditure; Dashed (blue) lines denote counter-factual consumption expenditure in the absence of international oil price shocks.

Figure 13.2 shows that some economies have benefited from changes in the international price of energy while others have been hurt. Expectedly, major oil importers China and Japan are negatively affected by oil price changes, which have generally been increasing over the analysis period. Interestingly, but still not surprisingly, the oil exporters (Singapore who import crude oil and export refined oil products, and Indonesia and Malaysia who export crude oil) have benefited from rising international oil prices where the extra revenue to the economy from oil exports enables higher levels of consumption to be sustained. Meanwhile, the rest of the countries in this study (notwithstanding Thailand) would have had higher levels of household consumption had the international oil price not been fluctuating over time.

The results for Thailand are, on the surface, thought provoking. The country is perhaps the most unstable (economically and politically) of all of the nations in the sample, and this paper makes no real effort to justify these findings. The ECM for this country has very low explanatory power, suggesting that more work may still be needed in the estimation.

Preliminary results have shown some interesting findings. Oil shocks do impact household consumption decisions in the short run, and these effects show clear asymmetries. The ECM coefficient is of course important, but on itself conveys only a limited message. Counter-factual assessment of the domestic household consumption had international oil shocks not occurred proves enlightening.

One key message is that international oil shocks are actually good news for many countries; hence, regulations against international oil shocks may not be as advisable as it may first appear. While most of the economies in the

ASEAN and East Asia area are trying to make their domestic oil market more flexible towards free markets, it might be worth thinking carefully what the appropriate speed and timing of liberalisation must be.

Energy market integration opportunities are a focus within the region. The results here offer some indirect insights. That is, collaboration and integration may be helpful in terms of risk sharing/hedging against international price shocks or optimizing resource allocation; however, the stronger economies must be prepared to play their part.

Policy Implications and Conclusions

A core purpose of this study is to add new evidences on energy market interactions in the region and then to consider how the evidences contribute to EMI. Energy market integration is a desired objective for the region. After all, energy is naturally an industry with substantial scale economies (e.g., in power generation), and creates a need for cross-border trade since many of the energy resources (e.g., oil and coal reserves) are not located in the same place where they are consumed.

Broadly speaking, international oil shocks are a common concern facing all countries in the region, either directly or indirectly. As the ASEAN and East Asia combined is a heavily oil-importing region with very close geographical ties and in many cases very close historical relationships, establishing a platform for shared debate and shared resilience to international markets would have several advantages.

By definition, an important aspect of the EMI is the "market", which is broadly composed of three players: suppliers, consumers, and a governing body. Existing research works in relation to a possible EMI already reveal substantial information on the state of governance in the region---for example, overlapping political systems and general energy market regulation---although there is still room for increased transparency in governance, as will be discussed further below. Likewise, there is a growing body of evidence on EMI in the production (or supply) side of the picture. Now, what this paper here attempts to do is to provide an assessment on the demand side from one perspective so as to identify what additional considerations are needed for a comprehensive EMI.

When considering the EMI opportunities that the results imply, there are several points to keep in mind. For one, existing studies that had looked at the energy supply of the regional economies prove that market integration is feasible. However, by focusing on the pass-through effects of oil prices to the consumer side of the economy, it can be shown that a more complicated picture prevails. Reactions to international energy shocks differ widely, due in part to the differing levels of scale and economic development, as well as to the differing dependencies on imported oil/energy. This implies a need for a different type of strategy towards EMI on the demand side. Lessening the impact of oil shocks on those countries more severely affected would help smoothen consumption in the region and therefore support regional integration in energy.

Just a word of caution: A comprehensive EMI (i.e., integration across supply, demand, and governance) is not supported immediately by this study's results, nor should it be. By making the consumer side of the economy the point of focus here, this study makes it more apparent that there are important specificities across countries in the region. These are a result of differing lifestyles, social structures, attitudes to religion, political systems, resource endowments, levels of development, education, etc. Accordingly, households' energy consumption patterns are likely to differ widely from one country to the next. For example, Indonesia and Singapore each represents opposing ends of the economic development spectrum.

While consumers across countries might aspire to have similar energy supply technologies with common regulation over suppliers, they will still have differing energy consumption demands consistent with their differing lifestyles. Thus, a comprehensive EMI must have looser boundaries for acceptable integration on the consumer side.

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