Data Collection Survey on
Long-term Energy Policy in ASEAN
(Model Building)

Final Report

March 2014

JAPAN INTERNATIONAL COOPERATION AGENCY

THE INSTITUTE OF ENERGY ECONOMICS, JAPAN

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Appendix – A: Detail Diagram for Simulation Analysis
Appendix - B: Energy Outlook of ASEAN Countries

Abbreviations

ARI	Asiam Research Institute. Inc
ASEAN	Association of South‐East Asian Nations
A-USC	Advanced Ultra-super Critical
BAT	Best Available Technology
BAU	Business as Usual
Bcf	Billion Cubic Feet
BOT	Build Operate Transfer
BP	British Petroleum
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DMO	Domestic Market Obligation
DOE	Department Of Energy
DU	Distribution Utilities
EC	Electrification Cooperatives
EDC	Energy Development Cooperation
EFOM	Energy Flow Optimization Model
EPIRA	Electric Power Industry Reform Act
FIT	Feed-in Tariff
GHG	Greenhouse Gas
GMS	Great Mekong Sub-region
GNI	Gross National Income
ICPR	Indonesian Coal Price Reference
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
IMEM	Interim Mindanao Electricity Market
IMF	International Monetary Fund
IPP	Independent Power Producer
IRR	Internal Rate of Return
JETRO	Japan External Trade Organization
JICA	Japan International Cooperation Agency
LC&E	Low Carbon & Energy Efficiency
LP	Linear Programming
MARKAL	Market Allocation Model
MERALCO	Manila Electric Company
MOF	Ministry of Finance

MOIT	Ministry of Industry and Trade
NCEIF	National Centre for Socio-Economic Information and Forecast
NEA	National Electrification Administration
NGCP	National Grid Corporation of Philippines
NPC	National Power corporation
O&M	Operation & Maintenance
OECD	Organisation for Economic Co-operation and Development
OPEX	Operating Expense
PDP	Power Development Plan
PEMC	Philippine Electricity Market Corporation
PM	Particulate Matter
PPP	Purchasing Power Parity
PSALM	Philippines Power Sector Assets and Liabilities Management
PV	Photovoltaics
ROCA	Retail Competition and Open Access
RPS	Renewables Portfolio Standard
SC	Super- Critical
SHS	Solar Home System
TRANSCO	National Transmission Corporation
UCT	Unconditional Cash Transfer Program
USC	Ultra-super Critical
VIP	Vietnam Indonesia Philippines
VND	Vietnam Dong
WASP	Wien Automatic System Planning
WESM	Wholesale Electricity Spot Market

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Executive Summary

Background of Study

Today ASEAN countries are deemed as one of the world growth centers for next several decades. Accelerating income growth and urbanization will push up energy consumption in the region, in particular electricity. Since energy is the fundamental element of economic activities, establishment of an optimal energy supply structure is essential for sustainable development as expected. In the contemporary world, we are required in pursuit of this to target energy security and greenhouse gas emissions reduction consistently.

There are many preceding studies on this subject. However, these studies have analyzed only a little on the issues how we should arrive at an optimal energy supply structure, what would be the desirable policy mix, how the energy supply structure would deviate from the target by adopting or not adopting some policy measures, what will be the cost of such policies, what will be the impact on energy tariffs, etc. Such analyses are crucial to establish policies and action plans to orient an economy on to an appropriate development path.

Under the above circumstance, the Study Team of The Institute of Energy Economics, Japan (hereinafter referred to "IEEJ") has constructed a model for simulations on the subject, so as to identify desirable pathways for electric power development. This study is conducted through the guidance of JICA in collaboration with Castalia Limited (hereinafter referred to "Castalia") of the USA, who prepared a theoretical framework for the analysis while the IEEJ constructed the analytical model.

Purpose of the Study

There are several analytical tools for electric power development planning. Among the tools popular in ASEAN and other developing countries are MARKAL (Market Allocation Model), EFOM (Energy Flow Optimization Model), WASP (Wien Automatic System Planning), and experimental new tools are being introduced in the US and Canada which are able to analyze selection of renewable energies.[1]

These tools, however, represent a model to produce an optimal plan only for a period of 10 – 20 years and as extension of the existing infrastructure and technologies. However, electric facilities are generally of super long life over 20-30 years and require a huge amount of initial capital investment. The existing tools are often not quite appropriate to analyze an extremely long period up to 2050; the existing infrastructure will be mostly replaced and conditions for technology progress will be totally different for such a super-long period. In addition, these tools are big and heavy and often with black boxes unclear for users. They require special expertise to operate, but not friendly for policy makers.

[1] There are other types of modeling software such as LEAP, MEDEE, and MESAP. They provide accounting frameworks to simply examine the implications of a scenario, but they are not a tool for optimization.

Under the circumstance, we have constructed a new model for power mix optimization. Using a software Simple.E as an “add-in” to Excel, it is developed on Excel spread sheets to be easy to use for everybody. All the logics are written explicitly to be easy to follow. Thus, we hope this handy and transparent model will become a strong tool for policy makers and energy analysts.

However, since we are given only a limited time for this Study, it was difficult to develop a realistic model applicable to each objective country considering their specific features. In this regard, we considered the following points as a realistic solution;

a. Limit the number of variables to be fabricated in the model as small as possible, and define the relationship and logic of them as simple as possible.
b. Apply flexible arrangement on the relationship of variables.

Thus, the present model is a general prototype one to produce logical solutions under given assumptions. However, it is yet to be refined and tuned to produce a realistic solution incorporating various conditions surrounding energy issues which are diverse among countries. Its value is yet to be established through practical application for policy planning.

Application of the Model for Analytical Simulation

Under given conditions, the model is designed to search for optimum supply schedule including investment timing and capacity of each plant considering available annual capacity, reserve margin, minimum/maximum operation hours, peak load allocation and other important elements against the objectives such as economics (i.e., minimum cost), GHG emissions target, etc. After iteration of optimization trial for annual and the resultant accumulated outcome, the model will eventually find the solution for the accumulated optimum level of power mix for the entire objective period. The detail of the model is explained in Chapter 4.

From the researches on the preceding studies, we take in those major variables in the model that will impact long term economic growth of the whole ASEAN region. On the individual countries, we have considered specific features and conditions of these countries relating to energy, such as market-economy, planned-economy, subsidies and taxes, etc., existing institutions, and their long-term strategies and so on, and have conducted analytical simulation on the following points;

a. what kind of policies will be necessary or preferable in order to establish a desired energy supply structure
b. what will be their impact on energy tariff and environment
c. what will be their impact on the regional energy security

To this end, the model is designed to yield major outputs of the simulation as follows:

1) Indicators of affordability such as total cost, total revenue, total subsidies/taxes, social cost as total government outflow, and unit electricity cost, etc.
2) Power mix in capacity (GW) and generation amount (GWh), and shares by energy
3) Share of low carbon energies, emissions of CO_2, NO_X, and PM

Analyzing these outputs, we aim to sort out policy recommendations supported by quantitative analyses.

Result of Trial Simulation

Using the model with assumptions set out as explained in Chapter 4, various cases were run for Vietnam, Indonesia, Philippines and the whole ASEAN region. Starting with the Reference scenario (BAU: Business as Usual case), several scenarios are set to consider impacts of policy actions on the following issues;

1) Energy Saving
2) GHG reduction
3) Desirable generation mix
4) Effect of FIT and/or fuel subsidy reduction
5) Different fuel prices

Major findings from the above analyses are as follows:

1. Achieving CO_2 reduction target will require higher generation cost, requiring significant switching from coal, which is cheaper, to natural gas, which is more expensive in the Asian market.
2. Improvement of thermal efficiency is the most effective solution for reducing generation cost and fossil fuel consumption, as well as for conserving domestic energy resources. It should be noted that, despite the larger initial investment, enhancing energy efficiency is more economically beneficial in the long run.
3. Coal-fired power plants can reduce total generation cost. Concerns are the very heavy dependence on coal-fired plants with regard to GHG emissions. Policy makers are required to find a good balance between affordability and these concerns.
4. Feed-in tariff is not effective, if it is set low, to promote renewable energies.
5. Fuel subsidy increases pressures on the state finance, while reduction in electricity unit cost for end-users is minimal. This is a touchy issue for politicians. However, for consumers, it is not more than the choice of higher tax or higher tariff.

The above simulation results induced by the model constructed this time are quite a common-sense outcome. It is a proof that the model is structured properly and working normally. As this model does not have any black box, it is possible to trace accurately how the solution is produced reflecting assumptions and through technical and economic logics. Using such model, policy makers will be able to conduct evaluation of policy options without theoretical contradiction or magical rhetoric.

The faster the ASEAN countries develop the more important for them to set out proper energy policies and implement them steadily step by step. To this end, we hope that this transparent model with a sense of reassurance will become a strong weapon for policy makers and energy analysts in the region.

Next Steps

From the above outcome, our much simplified model looks producing logical consequences. However, we should note that data and assumptions given to the model for each scenario are still preliminary ones, and it is necessary to upgrade them before we proceed to the next step for substantive discussion on energy policy planning. In particular, more accurate data and information on the local conditions are essential. In addition, it is also necessary to examine whether the indicated pathway during the projection period for each scenario is sound and sustainable. We need to fine tune the model in this regard.

We trust this simple and transparent model is handy for use for many policy makers. Thus, we hope to disseminate it among ASEAN countries via various activities, and would like to upgrade it through practical application. To this end, we look forward to comments and cooperation of various stakeholders.

Chapter 1 Introduction

1.1 Background of the Study

Since energy is the fundamental element of economic activities, establishment of an optimal energy supply structure is essential for sustainable development of ASEAN economies. In the process to materialize this objective, we need to establish long term energy demand outlook, desirable energy supply mix reflecting social aspiration on economic development, global environment and other objectives, pathways to reach there, and policy measures to ensure the journey right on the track. Among various elements, an important policy issue is simultaneous achievement of low-carbonization and energy efficiency consistently with energy security.

On the energy supply side, the Shale Revolution presently dominating in the North America may trigger substantial changes in international energy prices. Further evolution will be brought in on the thermal power plant efficiency technology. New policy measures such as RPS and FIT are being adopted in the ASEAN countries.

On the demand side, there are increasing concerns on energy efficiency among consumers (both industry and household) in Southeast Asia in their purchasing behaviors. Concerns on low-carbonization are also increasing. However, impact of such trend on the demand side influencing the energy supply in the long-run is yet to be assessed.

In the Southeast Asia, there are many preceding studies on the long term energy demand outlook, even targeting 2050, and the optimal energy supply structure, as well as national mitigation plans and other national targets. However, these studies have analyzed only a little on the issues how we should arrive at an optimal energy supply structure, what would be the desirable policy mix, how the energy supply structure would deviate from the target by adopting or not adopting some policy measures, what will be the cost of such policies, what will be the impact on energy tariffs, etc. Such analyses are crucial to establish policies and action plans to orient an economy on to an appropriate development path.

Under the above circumstance, this study is conducted through the guidance of JICA in collaboration with Castalia Limited (hereinafter referred to “Castalia”) of the USA, who prepared a theoretical framework for the analysis while The Institute of Energy Economics, Japan (hereinafter referred to “IEEJ”) constructed the analytical model. In the course of the study, consideration has been paid on the impact of certain policy on the energy tariff and/or its cost. Also, various preceding studies were reviewed and utilized.

1.2 Outline of the Study

Based on the above analysis, this Study aims to conduct analytical simulation on how to arrive at the desirable energy supply structure in 2050 for the ASEAN economies, in particular for the Philippines, Indonesia and Vietnam, for improvement of the existing policy framework to materialize desired energy supply structure.

The study outputs are as defined below.

1) Reviewed preceding studies on energy supply structure of the whole ASEAN and the Philippines, Indonesia and Vietnam up to 2050.
2) Constructed an energy supply mix model for analysis of long term energy supply and demand balance, in particular the electricity sector.
3) Studied on energy policy measures, classified in two groups aiming at low-carbonization (including promotion of renewable energy) and energy efficiency, and also examine effect of government driven policies and market driven policies.
4) Held a symposium on December 13, 2013, in Tokyo inviting panelists from ASEAN countries and local audience among ASEAN government officers, donors, academies, medias and other stakeholders.
5) Held workshops in February 2014 on the study outcome in the Philippines, Indonesia and Vietnam, outcome of which will be incorporated into the Final Report.

1.3 Progress of the Study

In July 2013, the IEEJ Study team started research on preceding studies on energy outlook, energy price and desirable energy supply structure up to 2050 for developing assumptions and constructing an energy supply optimization model for power development. The energy supply mix model for analytical simulation is being designed to evaluate effect and impact of policy measures, which will be classified into:

a. Two groups of those targeting low-carbonization (including promotion of renewable energies) and those targeting energy efficiency, and
b. Two groups of policy systems which are government-driven and market-oriented
c. Among others, the model should be able to conduct detail assessment on the power generation mix.

The model shall simulate cases on how to build the optimal energy supply structure with a combination of various cases, and the extent of deviation from such target by adopting or not adopting a specific pattern. In particular, quantitative analysis should be conducted on the impact of the energy tariff and cost.

Under coordination of JICA and via telecommunication, both parties exchanged information and views sets to be analyzed and indices/parameters to be adopted in the interface of the model analysis and its interpretation. In September, 2013, basic patterns of case selections considering the fundamental structure of the model and specific features of the objective areas were examined as aggregating previous discussions. Based on the discussion, the first model was built and a trial base (BAU) case was run. The outcome was further discussed through October and November repeating fine tuning of assumptions and the model comparing various test run outcome. The above method of approach and the interim study outcome were also referred to the Advisory Committee in Tokyo comprising experts on electricity planning for their comments.

The Symposium on "Pathways to Low Carbon and Efficiency in ASEAN" was held on December 13, 2013 in Tokyo, and the outcome of the above study was presented and discussed. Panelists from the Philippines, Indonesia and Vietnam were invited to contribute their valuable comments on the interim outcome, as well as about 100 participants, from among government officers, ASEAN stakeholders staying in Japan, donors, media, academies, etc.

Incorporating the discussion at the Symposium and other meetings, the Study Team has further adjusted assumptions and the model, and run case studies in consideration of simultaneous achievement of low-carbonization and energy efficiency, impact on the energy tariff and cost of policy for the objective areas.

The Study Team has held workshops in February 2014 in the above three countries and made presentation on the energy mix model and simulation outcome analyzed under this Study, and exchanged views and opinions with participants at each occasion.

Incorporating the foregoing study and discussions, the Study Team has compiled this Final Report for submission to JICA.

Chapter 2 Status of Power Supply in VIP and ASEAN Countries

2.1 Vietnam

Table 2.1.1 Key Indicators

		2011
1) GDP (nominal)	Billion US Dollars	123.7
2) Population (as of 1 July)	Million person	87.8
3) Per capita GDP	US Dollars/person	1,408
4) Total Primary Energy Supply (TPES)	Million tonnes oil equivalent (MTOE)	61.2
5) Energy Self-supply Ratio	-	108.8%
6) Electricity Consumption	Tera WH (TWH)	90.9
7) Power Generation Capacity	Million kW	26.1(2012)
8) CO_2 Emissions (energy origin)	Million tons CO_2 equivalent (Mt-CO_2)	130.5(2010)
9) Per capita Primary Energy Supply	TOE/person	0.697
10) Energy Intensity per GDP	TOE/Thousand USD	0.495
11) Per capita Electricity Consumption	kWh/person	1,035
12) Electrification rate [2009]	-	98%(2012)
13) Electricity Intensity per GDP	kWh/Thousand USD	735
14) Per capita CO_2 Emissions (energy origin)	Ton-CO_2/person	1.501(2010)
15) Primary Energy Supply Composition	Coal	25.4%
	Oil	33.5%
	Natural Gas	12.2%
	Nuclear	0.0%
	Hydro	4.2%
	Geothermal	0.0%
	Other Renewables	24.0%
16) Energy Self-sufficiency	Total	108.8%
	Coal	160.4%
	Oil	82.7%
	Natural Gas	100.0%
Source:IEA, ADB, MOIT, etc		

2.1.1 Economic Conditions

The Vietnamese economy has remained strong since 2000, with an average annual rate of growth during the period from 2000 to 2010 reaching 7.2 %. In June 2010, the Vietnamese government announced the latest five-year plan for the period 2011-2015[2]. The plan set a target of an average annual rate of GDP growth over the next five years between 7-8%, and for the country to basically become a modernity-oriented industrial nation by 2020. However, because of general international economic conditions, structural factors of the domestic economy in Vietnam, and a lack of power supply, economic growth after 2010 has slowed. According to a report by the IMF[3], GDP growth in 2012 did not exceed 5.0%, registering the lowest level since 2000.

For economic growth in 2013, the National Centre for Socio-Economic Information and Forecast

[2] MPI, “National 5 Year Socio-economic Development Plan (2011-2015)”, June 2010

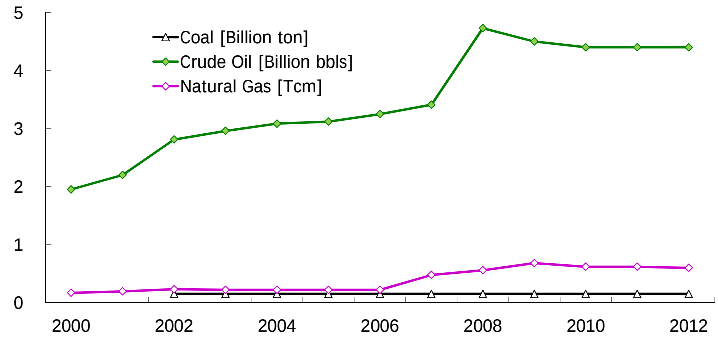
[3] IMF, “World Economy Outlook 2013”, September 2013

(NCEIF) under the control of the Ministry of Planning and Investment (MPI) forecasts that it will end up at 5.7% at the most. However, it is predicted that as the corporate tax rate will be lowered from 25% in the past to 22% in 2014, and as a result corporate activity will become more vibrant, leading the Vietnamese economy gradually in the direction of recovery during 2014-2015[4]. According to the country-wise projections in the IMF's World Economy Outlook 2013, gross domestic product (GDP) of Vietnam in 2012 recorded US$138.1 billion, and the per capita GDP reached US$1,528. In addition, the rate of GDP growth in 2013 is expected to be 5.2%, and an average annual rate of GDP growth in the 2012-2018 period is forecast at 5.4%.

Concerning an ultra-long-term economic outlook of Vietnam, the Institute of Energy Economics, Japan (IEEJ) has predicted an average annual rate of GDP growth during the periods of 2011-2020 at 5.7%, 2020-2030 at 5.8%, and 2030-2040 at 4.5%[5].

2.1.2 Energy Supply and Demand

Vietnam is endowed with coal, oil and natural gas resources, though they are not very significant. Extensive exploration activities on oil and natural gas are being carried out in offshore blocks, which are expected to bring new reserves. As some of natural gas reservoirs in northern territories contain high CO_2, sophisticated technologies will be needed to develop them commercially. Developing the coal seams underneath the shallow river bed of the Hon river delta will add coal production significantly, once appropriate technologies for safe production is developed.



Source: BP Statistics 2013

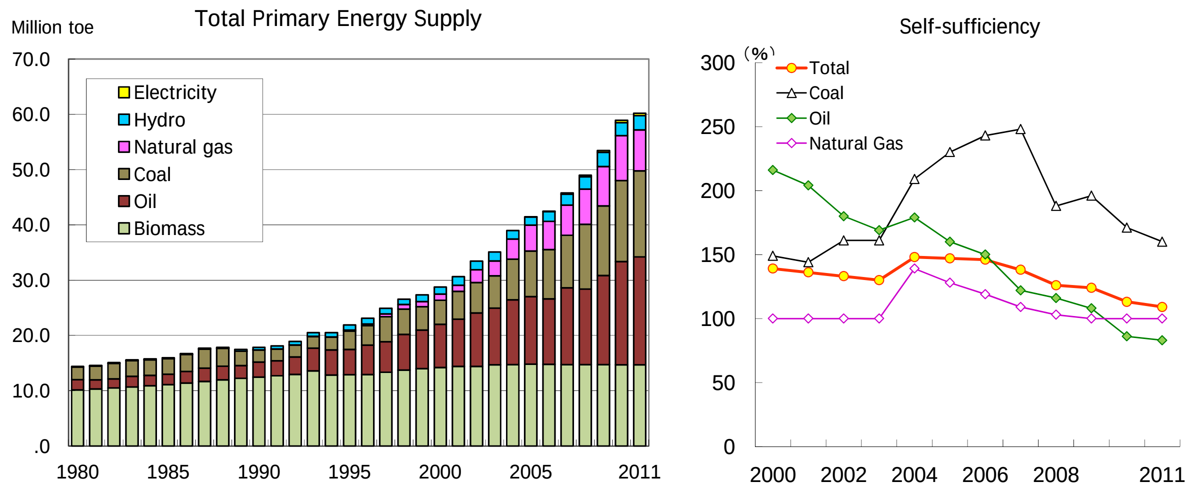
Figure 2.1.1 Energy Resources of Vietnam (Proved Reserves)

The primary energy supply in Vietnam has been expanding at an accelerated pace since 2000 and recorded 61.21 million tons of oil equivalent (MTOE) in 2011. Since 2000, consumption of commercial energy excluding biomass increased by 11.0% per annum, thus lowering the share of biomass from 50% in 2000 to 25% in 2011. Of the primary energy supply, oil accounted for the largest share of 35%. Driven by the increase in power demand, consumption of coal as the main fuel increased from 15% in 2000 to 25% in 2011, and so did natural gas, from 4% in 2000 to 12% in 2011. In addition, Vietnam is importing hydroelectric power from neighboring Laos and China for a quantity equivalent to 0.7% of total primary energy supply. According to a projection by the

4 http://www.morningstar.co.jp/msnews/news?rncNo=1210034 (in Japanese)

5 IEEJ, "Asia/World Energy Outlook 2013", October 2013

IEEJ (previously cited), energy consumption of Vietnam will continue its robust growth in the future, raising its primary energy supply to 91 MTOE in 2020, and to 144 MTOE in 2030. Vietnam has prided itself of a high energy self-sufficiency rate and exported crude oil and coal in the past. However, after 2010 it turned to a net oil importer, and the ratio of import is expected to go even higher in the future. Sooner or later, importation of natural gas (LNG) and coal will also begin mainly as the fuel for power generation.

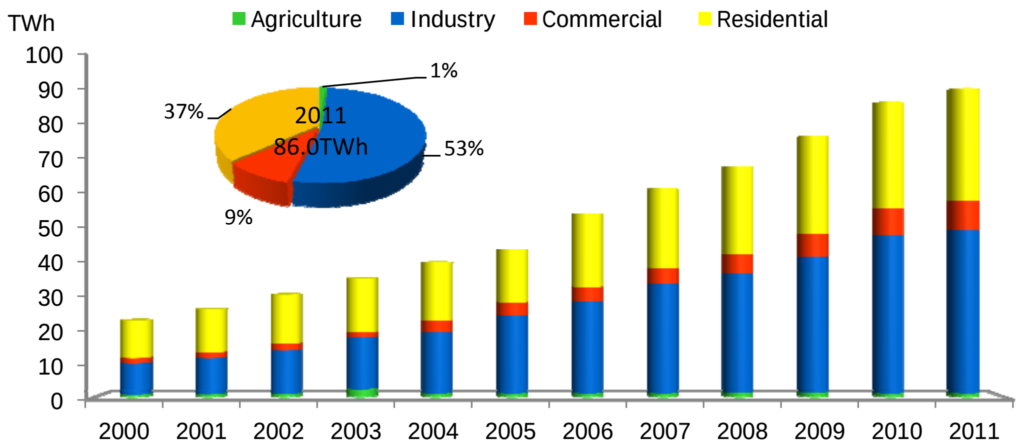


Source: Energy Balances of Non-OECD Countries 2013, IEA

Figure 2.1.2 Primary Energy Supply in Vietnam and Self Sufficiency Rate

2.1.3 Power Demand

Electricity demand in Vietnam has increased every year along with its economic growth. According to the Ministry of Industry and Trade (MOIT) data, power consumption in 2012 amounted to 117 billion kWh, which is 5.2 times the 2000 consumption at 22.4 billion kWh. During the period of 2000 to 2012, electricity demand recorded an average annual growth rate as high as 14.8%.



Source: IEA Statistics

Figure 2.1.3 Power Demand in Vietnam

According to the IEA statistics[6], power demand in Vietnam in 2011 was 90.9 TWh, in which industrial sector accounted for 53% of the total, followed by residential use for 37%, commercial use for 9%, and agriculture for 1%. Between 2000 and 2011, electricity demand in any of the sectors other than agriculture recorded an annual average growth of 10% or higher, while industrial sector registered 16.3% and the commercial sector reached as high as 17.0%. It can be said that the rapid industrialization such as above has been pushing up the power demand of Vietnam.

Amid the sharp and continuing increase in demand, the expansion of power supply capacity failed to keep up with the demand, leading to power failures and implementation of power use restriction measures in various regions of the country in 2013[7]. As a result heavy damage occurred in the areas such as industrial production, foreign investment, and others in the civilian sector. It is perceived that the value of the power demand in the statistics did not reflect the trend of actual demand which was far higher than the statistical data indicates[8].

On July 21, 2011, the government announced a Power Development Master Plan VII (PDP7)[9]. Based on an assumed GDP growth rate at 7-8% per annum for the period between 2011 and 2030, the plan set the growth rate of power demand for the period between 2011-2015 at 12.1%, 13.4%, and 16.1%, respectively for the Low-, Base-, and High-growth scenarios. Later in 2013, the MOIT revised the plan slightly upward by projecting 14.1-16.0% for the period between 2011-2015, 11.3-11.6% for 2016-2020, and 7.8-8.8% for 2021-2030[7]。

Meanwhile, the IEEJ (the ultra-long-term prediction previously cited) has predicted that the growth in electricity demand will gradually decline in the future, to 5.7% in the period between 2011-2020, to 5.8% in 2020-2030, and to 4.5% in 2030-2040. Although many institutions also predicted milder increases in demand in the past, whether the rates of growth in demand will calm down in the future as projected in the above or the high growth rates will continue as assumed in the Master Plan remains an undecided question for some time.

2.1.4 Power Supply

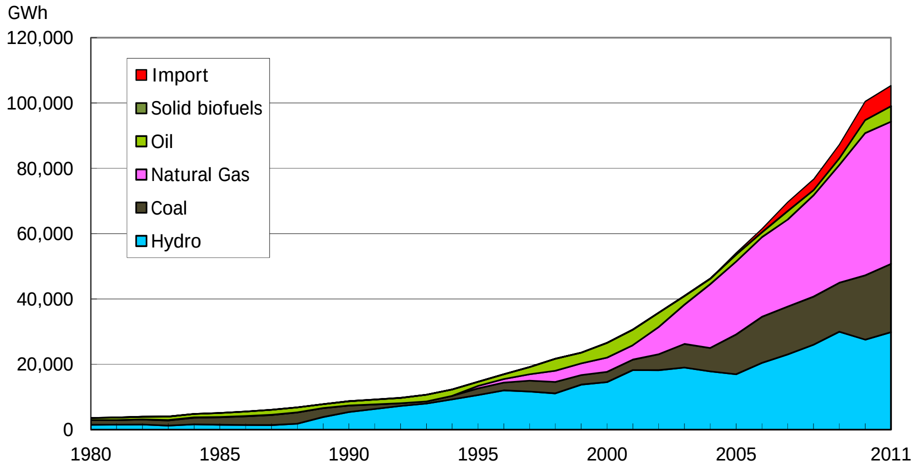
According to the IEA statistics, the amount of domestic power generation in Vietnam was 99.2TWh in 2011, wherein 43.5TWh (43.9% in the total power generation) was generated by natural gas-fired thermal power, 29.8TWh (30.1%) by coal-fired thermal, 20.9TWh (21.1%) by hydropower, 4.7TWh (4.8%) by oil-fired thermal, and the remainder 0.1% being power generated from renewable energy such as PV or biomass. With the addition of power imported from China at 6.2TWh, the total amount of power supplied in Vietnam was 104.3TWh in 2011.

6 IEA, "World Energy Statistics and Balances 2013"

7 JETRO Hanoi Office (Interview)

8 MOIT, "Country Brief of Vietnam", presented at "Energy Sector Reform Workshop", Manila, Philippines, Sept. 2013

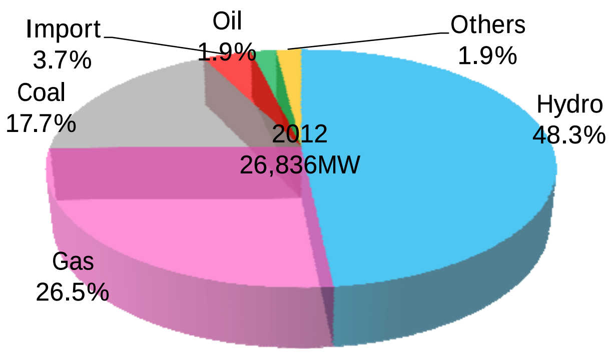
9 "National Master Plan for Power Development for the 2011-2020 Period" (No.1208/QD-TTg); also discusses many other plans such as restructuring of EVN and liberalization of electricity market, introduction of smart grids, and renewable energy development.



Source: IEA Statistics

Figure 2.1.4 Power Supply in Vietnam by Source

According to the MOIT data, domestic power generation capacity in 2012 stood at 25,843 MW, which increased to more than four times the 2000 figure of 6,235 MW. Although the generation capacity increased at a high annual average rate of 12.6% for the 2000-2012 period, because the power demand expanded at an even higher rate of 14.8% per annum, power development lagged behind in the end.



Source: JETRO

Figure 2.1.5 Power Generation Mix in 2012

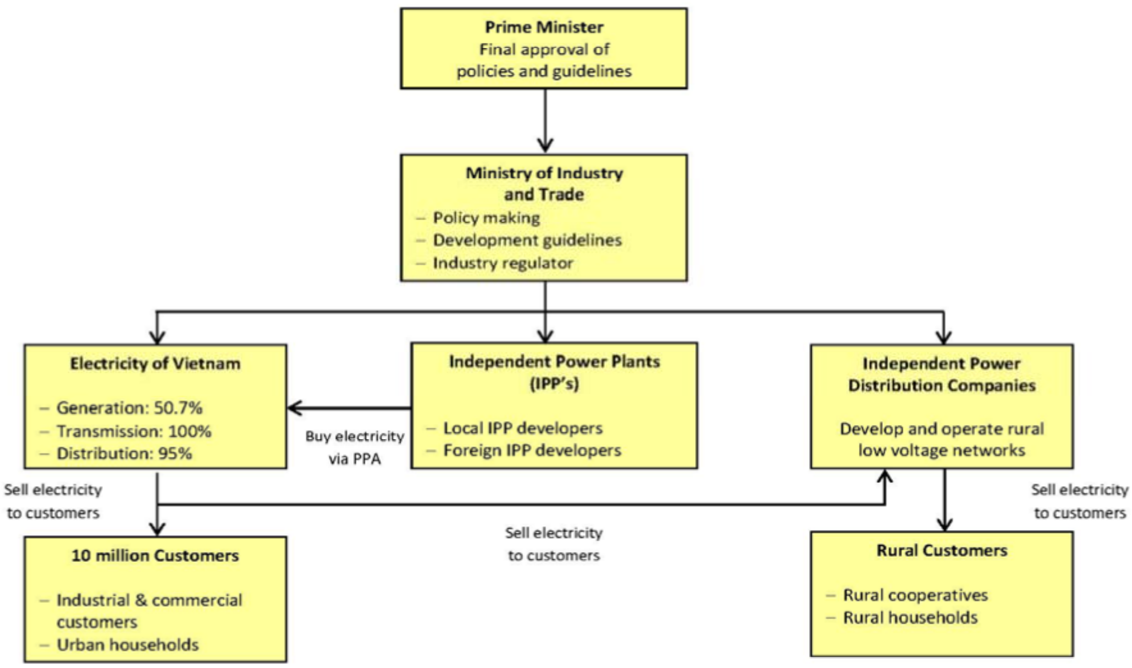
According to a study[10] by JETRO, installed capacity of natural gas-fired power generation at the end of 2012 was 9,831 MW (37.3%), whereas hydro power was 11,436 MW (43.3%), coal-fired thermal was 4,610 MW (17.5%), and oil-fired thermal 510 MW (1.9%). In addition, power imports from Laos and China are now operative and the capacity available through the international connection is relatively large at 993 MW.

[10] JETRO, "Survey on Vietnamese Power Supply Situation", September 2013

2.1.5 Power Utility Systems

Power industry in Vietnam is controlled by the MOIT, under which Vietnam Electricity (EVN) is currently responsible for electricity supply in Vietnam as a vertically integrated power utility. EVN was established in 1995 as a state-run power group by integrating the northern, central, and southern power sectors. EVN has a number of subsidiaries including those which are wholly owned and operated by EVN, wholly owned but are either financially or operationally independent, and joint stock companies (JSC) that are partially owned by EVN. As of 2011, EVN and its subsidiaries owned 68% of the total installed capacity, and IPP and BOT accounted for the remaining 32%[11]. In recent years, however, an increasing number of power plants are owned by private capital or by state-run corporations other than EVN. These IPPs or BOTs are supplying EVN with electricity under power sales agreements.

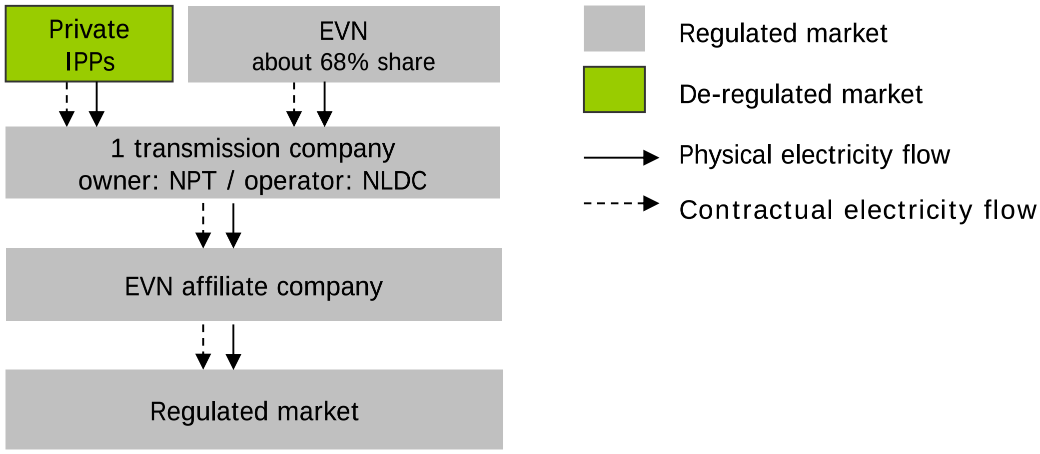
As shown in Figure 2.1.6, deregulation has been implemented only in power generation business in Vietnam. While EVN currently owns 100% of power transmission business and 95% of distribution business, in the future, power distribution utilities affiliated with EVN will be separated and divested as independent entities to further advance the marketization of power sector, with a roadmap setting out milestones toward 2020.



Source: PDP7

Figure 2.1.6 Electricity Administration System in Vietnam

[11] "Electric Power Situation in Vietnam", Japan Electric Power Information Center, May 2012

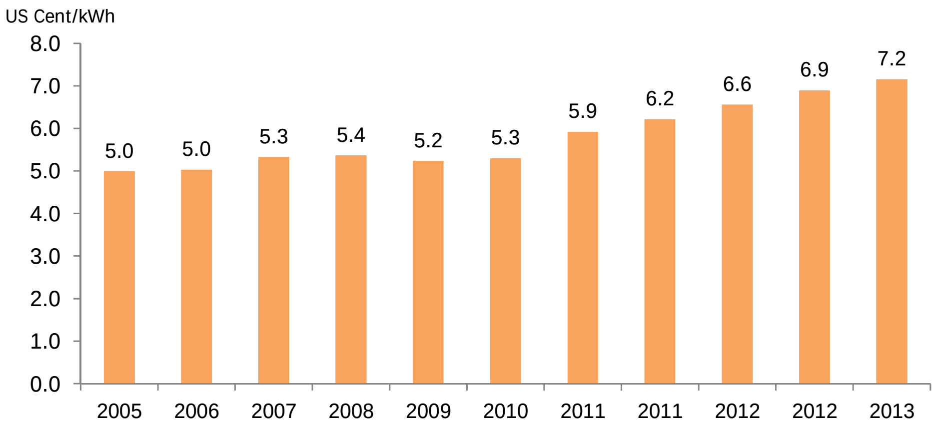


Source: Prepared by IEEJ from EVS and other data

Figure 2.1.7 Electricity Market of Vietnam

2.1.6 Power Tariff and Subsidies

According to the Vietnamese government data, the average electricity price in 2012 was 6.9 US¢/kWh (1,437 VND/kWh), and the same in 2013 was 7.2 US¢/kWh (1509 VND/kWh). Compared to the figure of 5.0 US¢/kWh (789 VND/kWh) for 2005, the average electricity price rose to 1.4 times (1.9 times in Vietnamese Dong) that of 2005.



Source: MOIT

Figure 2.1.8 Historical Electricity Prices

However, electricity rates in Vietnam are the lowest in ASEAN countries even today. Electricity prices in Vietnam are determined according to the amount of consumption by each consumer. Although there are no electricity subsidies directly payable by the government, there is a difference of four times between the electricity rates for affluent class (households with large power consumption) and that for the less privileged class (households with small consumption). Because electricity prices charged to the poor are lower than the average power generation cost, as a mechanism to compensate for the shortage, a so-called cross subsidy system is adopted with an extra charged against the wealthy. According to a Vietnamese government official interviewed, policy measures such as this are aimed for suppression of social unrest[12].

Table 2.1.2 Comparison of Electricity Prices between Vietnam/ASEAN

Country	Residential		Commercial		Industry	
	Low	High	Low	High	Low	High
Brunei	3.82	19.11	3.82	15.29	3.82	3.82
Cambodia	8.54	15.85	11.71	15.85	11.71	14.63
Indonesia	4.6	14.74	5.93	12.19	5.38	10.14
Lao PDR	3.34	9.59	8.8	10.36	6.23	7.34
Malaysia	7.26	11.46	9.67	11.1	7.83	10.88
Myanmar	3.09	3.09	6.17	6.17	6.17	6.17
Philippines	21.1	24.83	19.93	22.94	18.15	19.37
Singapore	19.76	19.76	10.95	18.05	10.95	18.05
Thailand	5.98	9.9	5.55	5.75	8.67	9.43
Vietnam	**2.91**	**9.17**	**4.38**	**15.49**	**2.3**	**8.32**

Source: Prepared with Internet information

2.1.7 Power Development Plans

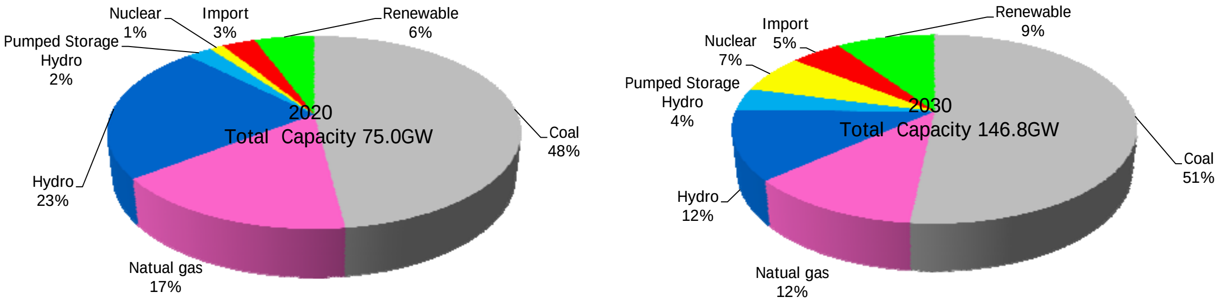
According to JETRO's study conducted in 2012, power supply shortages were common in all over Vietnam, and power failures and restriction measures on power use were frequent especially in the southern and central regions of Vietnam. Further, JETRO anticipated that such power shortages would not be improved until 2020 or later[13].

For power development plans for the future, in the 2013 edition of the "National Master Plan for Power Development for the 2011-2020 Period" (PDP7), installed power generation capacity in Vietnam is projected to reach 75,000 MW by 2020, and 146,800 MW by 2030. The plan also expects to introduce nuclear power by 2020 initially to occupy 1.3% (975 MW) of the total generation capacity and to further expand to 6.6% (9,700 MW) by 2030.

Elsewhere, the PDP7 anticipates that coal-fired power generation will account for about one-half of the total installed capacity by 2030. Although coal-fired power plants in Vietnam have so far been concentrated in the coal-producing region in the north, after 2015, coal-fired power plants fueled by imported coal are planned to start operations in the southern region. With the massive introduction of coal-fired power generation facilities, it is concerned that GHG emissions may significantly increase along with the air pollution in the vicinity of the plant site.

[12] Interviews conducted in Vietnam.

[13] JETRO, "Survey on Vietnamese Power Supply Situation", September 2013



Source: PDP7

Figure 2.1.9 Vietnam Power Mix, 2020 vs. 2030

In relation to the above, in the study by the IEEJ (previously cited), the amount of power generation in Vietnam is forecast to increase from 99 TWh in 2011 to 163 TWh in 2020, to 285 TWh in 2030, and to 444 TWh in 2040. In terms of power mix, while the share of hydroelectric power is projected to decrease gradually due to resource constraints, where coal and natural gas will support the power supply, the natural gas-fired thermal power is likely to play a major role for the reason of CO_2 emissions reduction.

It should be noted that, according to the above study, the introduction of nuclear power will delay considerably from the plan given in the PDP7, and expected to take place sometime after 2030.

Table 2.1.3 Projected Power Generation Output

	Power Generation (TWh)				Composition (%)			
	2011	2020	2030	2040	2011	2020	2030	2040
Coal	21	41	69	130	21	25	24	29
Oil	4.7	4.3	3.9	3.5	5	3	1	1
Natural Gas	44	72	125	195	44	44	44	44
Nuclear	-	-	25	45	-	-	9	10
Hydro	30	46	61	69	30	28	21	16
Geothermal	-	-	-	-	-	-	-	-
NRE	0.1	0.4	0.5	0.9	0	0	0	0
Total	99	163	285	444	100	100	100	100

Source: IEEJ Asia/World Energy Outlook 2013

Concerning the capital investment required in the future for the above power development program, the PDP7 estimates a total of US$110.3 Billion will be needed for the period of 2011-2030, of which expenditures needed in the construction of power transmission and distribution facilities are estimated to be US$46.0 Billion[14]. When estimated based on the investment amount and the capacity to be newly installed, it appears that the average costs of power generation facilities are assumed at 1,009 US$/kW for 2020, and 920 US$/kW for 2030.

[14] MOIT, "Country Brief of Vietnam", presented at "Energy Sector Reform Workshop", Manila, Philippines, Sept. 2013

Table 2.1.4 Power Sector Capital Investment Plans

(in Million US$)

Period	2011～2015	2016～2020	2021～2025	2025～2030	Total
Generation	22,076	28,830	27,005	32,441	110,352
Transmission/Distribution	7,245	10,523	12,345	15,868	45,981
Total	29,321	39,353	39,349	48,280	156,333

Source: PDP7

2.1.8 International Power Grid Interconnections

In the PDP7 announced in 2011 for the period 2011-2020, basic policies for international power grid interconnections and power development in the future were set out as follows:

Power export/import:

Implement efficient electricity trading with countries in the region while ensuring mutual benefit; promote exchanges of information with the countries excelling at hydropower generation such as Laos, Cambodia, and China; ensure stable operation of the transmission grids; and increase electricity importation with targeted amount of power to be imported being about 2,200 MW in 2020 and about 7,000 MW in 2030.

Grid interconnection with countries in the region:

Promote cooperation with countries in ASEAN region and the Mekong Sub-region (GMS) on the power trade to implement the power grid interconnection programs.

In the PDP7, based on the above-mentioned basic policy for the power grid interconnection with relevant countries in the region, interconnection plans are given as shown in Table 2.1.5. These plans are drawn mainly with an eye on the utilization of hydropower resources held in the neighboring countries, such as the Mekong river system in Laos and Cambodia and the upstream region of Red River ("Hong He") in Yunnan, China, where several hydropower projects have started to take shape.

Table 2.1.5 International Connectivity per PDP7

Connectivity	Receiving Area	Voltage Level
Northern Laos	Thanh Hoa Province, Nho Quan (Ninh Binh Province), Son La Province	220kV, 500kV
Central/Southern Laos	Thach My (Quang Nam Province), Pleiku (Gia Lai Province)	220kV, 500kV
Cambodia	(Unspecified)	220kV, 500kV
China	(Unspecified)	110kV, 220kV

Source: PDP7

Appendix：New facility construction plans up to 2015:

Table 2.1.6 New Capacity for Commissioning in 2012

Plant Name	Type	MW	Province
Son La #5,6		800	Son La
Dong Nai 4 #1,2		340	Dak Nong & Lam Dong
Dak Mi 4 #1,2,3,4		190	Quang Nam
A Luoi #1,2		170	Thua Thien Hue
Nho Que #1,2		110	Ha Giang
Na Le(Bac Ha) #1,2		90	Lao Cai
Ba Thuoc #3,4	Hydro	40	Thanh Hoa
Chiem Hoa #1,2		32	Tuyen Quang
Song Bung 5 #1		29	Quang Nam
Nam Phang #1		18	Lao Cai
Kanak #1,2		13	Gia Lai
Su pan #2		12	Lao Cai
Dak Mi 4C #5		9	Quang Nam
Mao Khe #1,2	Coal	440	Quang Ninh
Quang Ninh 2#1		300	Quang Ninh
Total		2,593	

Source: PDP7

Table 2.1.7 New Capacity for Commissioning in 2013

Plant Name	Type	MW	Province
Dak Rinh #1,2	Hydro	125	Quang Ngai
Nam Na 2	Hydro	66	Lai Chau
Sre Pok 4A	Hydro	64	Dak Lak
Vung Ang I #2	Coal	600	Ha Tinh
Mao Khe #1,2	Coal	440	Quang Ninh
Hai Phong II #1	Coal	300	Hai Phong
Nghi Son I #1	Coal	300	Thanh Hoa
An Khanh I #2	Coal	50	Thai Nguyen
Total		1945	

Source: PDP7

Table 2.1.8 New Capacity for Commissioning in 2014

Plant Name	Type	MW	Province
Thuong Kontum #1,2	Hydro	220	Kon Tum
Nam Mo (Laos)	Hydro	95	Laos
Nam Na 3	Hydro	84	Lai Chau
Yen Son	Hydro	70	Tuyen Quang
Dak Re	Hydro	60	Quang Ngai
Vinh Tan II #1,2	Coal	1,200	Binh Thuan
Thai Binh II #1	Coal	600	Thai Binh
Duyen Hai I #1	Coal	600	Tra Vinh
O Mon I #2	Coal	330	Can Tho
Hai Phong 2#2	Coal	300	Hai Phong
Nghi Son I #2	Coal	300	Thanh Hoa
Quang Ninh II #1	Coal	300	Quang Ninh
Total		4159	

Source: PDP7

Table 2.1.9 New Capacity for Commissioning in 2015

Plant Name	Type	MW	Province
Huoi Quang #1,2	Hydro	520	Lai Chau
Se Ka man 1 (Laos)	Hydro	290	Laos
Dong Nai 5	Hydro	145	Lam Dong
Dong Nai 6	Hydro	135	Lam Dong
Mong Duong II #1,2	Coal	1,200	Quang Ninh
Thai Binh II #2	Coal	600	Thai Binh
Duyen Hai III #1	Coal	600	Tra Vinh
Long Phu I #1	Coal	600	Soc Trang
Duyen Hai I #2	Coal	600	Tra Vinh
Cong Thanh #1,2	Coal	600	Thanh Hoa
Quang Ninh II #2	Coal	300	Quang Ninh
Luc Nam #1	Coal	50	Bac Giang
O Mon III	Gas	750	Can Tho
Total		6,390	

Source: PDP7

2.2 Indonesia

Table 2.2.1 key Indicators

		2011
1) GDP (nominal)	Billion US Dollars	846.8
2) Population (as of 1 July)	Million person	241.6
3) Per capita GDP	US Dollars/person	3,505
4) Total Primary Energy Supply (TPES)	Million tonnes oil equivalent (MTOE)	209.0
5) Energy Self-supply Ratio	-	188.8%
6) Electricity Consumption	Tera WH (TWH)	159.9
7) Power Generation Capacity	Million kW	44.1(2012)
8) CO_2 Emissions (energy origin)	Million tons CO_2 equivalent (Mt-CO_2)	410.9(2010)
9) Per capita Primary Energy Supply	TOE/person	0.865
10) Energy Intensity per GDP	TOE/Thousand USD	0.247
11) Per capita Electricity Consumption	kWh/person	662
12) Electrification rate [2009]	-	76.6%(2012)
13) Electricity Intensity per GDP	kWh/Thousand USD	189
14) Per capita CO_2 Emissions (energy origin)	Ton-CO_2/person	1.729(2010)
15) Primary Energy Supply Composition	Coal	15.1%
	Oil	34.8%
	Natural Gas	16.6%
	Nuclear	0.0%
	Hydro	0.5%
	Geothermal	7.7%
	Other Renewables	25.4%
16) Energy Self-sufficiency	Total	188.8%
	Coal	657.3%
	Oil	63.5%
	Natural Gas	204.3%

Source:IEA, ADB, MEMR, etc

2.2.1 Economic Conditions

According to IMF's "World Economy Outlook 2013", the Gross Domestic Production (GDP) of Indonesia was US$878.5 billion in 2012, and with the population of 240 million, per capita GDP was US$3,594, registering an average annual rate of GDP growth of 5.4% for the period from 2000 to 2012. According to the World Bank data on the economic contribution in 2012, the industrial sector output accounted for 43% of the GDP, the service sector 45%, and the agricultural sector 12%. In recent years, the service sector has recorded growth rates that are higher by two percentage points than GDP and the economy as a whole. These indicators suggest that the Indonesian economy is on a steady take-off trajectory. On the economic outlook for the future of Indonesia, the IMF estimates a 5.3% growth for 2013 and an average annual growth rate of 5.1% for the 2012-2018 period.

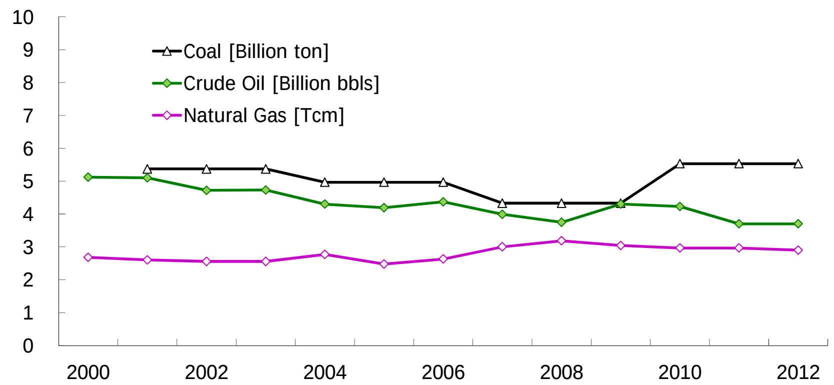
For the ultra-long-term economic outlook, the Indonesian government[15] projects an average

[15] National Development Planning Agency (BAPPENAS), June 2012

annual GDP growth rate up to 2030 at somewhere between 6.0 and 6.5%, which is higher than in the forecast of the IMF. Likewise, in its "World Energy Outlook 2013", the Institute of Energy Economics, Japan (IEEJ) forecasted an average annual rate of GDP growth of Indonesia at 5.1% for the 2011-2040 period. Although there are some differences in numbers, these forecasts agree in that "the Indonesian economy that so far gave an impression of lagging somewhat behind other ASEAN countries has started growing and will proceed with economic development at a much higher level in the future".

2.2.2 Energy Supply and Demand

In Indonesia, proven reserve of oil has been decreasing steadily, while that of natural gas is leveling off and that of coal has reversed its declining trend more recently. Oil and gas reserves of Indonesia are similar in size to those of Malaysia despite the fact that the country extends over a territory six times greater than that of Malaysia.

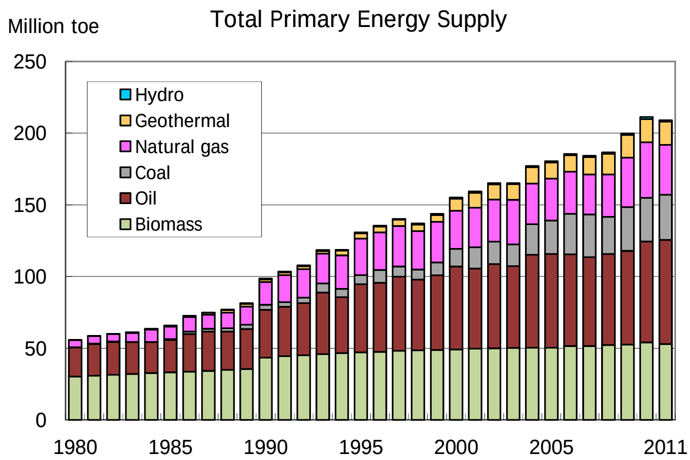


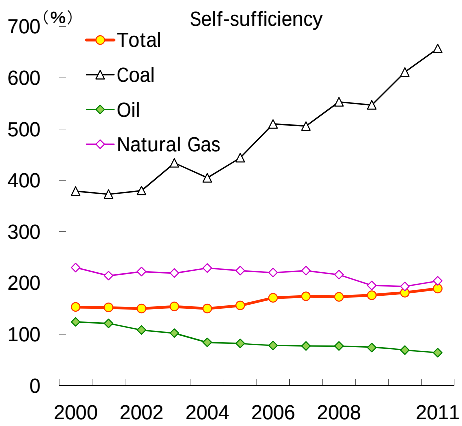
Source: BP Statistics 2013

Figure 2.2.1 Energy Resources of Indonesia (Proved Reserves)

The primary energy supply in Indonesia has been increasing steadily since 2000 and recorded 200 million tons of oil equivalent (MTOE) in 2010, and 209 MTOE in 2011. Since 2000, consumption of commercial energy excluding biomass increased by a relatively moderate rate of 3.6% per annum in average. As a consequence, the share of biomass in the total consumption declined from 32% in 2000 to 25% in 2011. Of the primary energy supply, oil accounted for the largest share of 35%, followed by natural gas for 17%, and coal for 15%. Geothermal energy is also well utilized in Indonesia, a volcanic country, and accounts for 7.7% of primary energy supply. According to a projection by the IEEJ (previously cited), energy consumption of Indonesia will continue its steady growth in the future, raising its primary energy supply to 310 MTOE in 2020, and to 413 MTOE in 2030.

Indonesia had been one of the leading energy exporting countries in the Southeast Asian economies in the past. However, in 2004 it turned to a net oil importer, and withdrew from the OPEC membership. Indonesia undertook a large-scale initiative to switch cooking fuel from kerosene to LPG from 2007 with a high degree of success, but the increasing trend in transportation fuel demand remains strong due to the robust economic growth. Unless a significant discovery of oil is made within the country in the future, it is expected that the increase in oil imports will continue. Natural gas has been exported via pipelines or as LNG until now, but its availability for export is on a declining trend due to growing domestic demand. Meanwhile, as the coal development progressed mainly in Kalimantan in the mid-2000s, the country became the world's largest exporter of steaming coal. However, in the face of growing domestic demand mainly for use in power generation, discussions have begun on the idea of export controls.





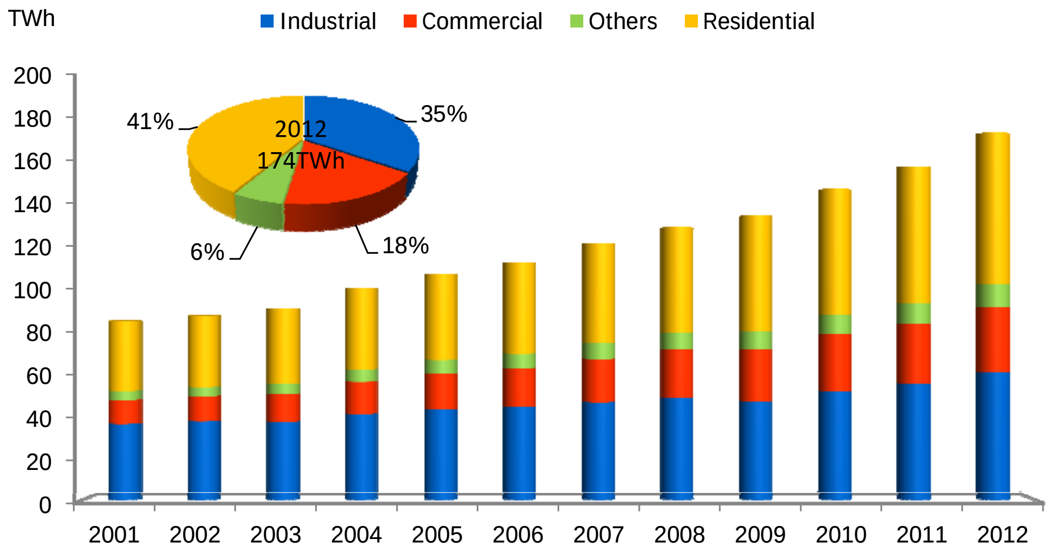
Source: Energy Balances of Non-OECD Countries 2013, IEA

Figure 2.2.2 Primary Energy Supply in Indonesia and Self Sufficiency Rates

2.2.3 Power Demand

Indonesia's power consumption in 2012[16] was 174.0 TWh in which residential consumption at 72.1 TWh accounted for 41.5% of the total, followed by the consumption in the industrial sector at 60.2 TWh (34.6%), commercial sector at 31.0TWh (17.8%), and others (such as the government and public service sectors) at 10.7 TWh (6.2%).

[16] PLN Statistics 2012



Source: PLN Statistics 2012

Figure 2.2.3 Power Demand in Indonesia

During the period of 2001 to 2012, Indonesia's electricity demand recorded an average annual growth rate of 6.8%, in which the commercial sector registered a highest rate of 9.5% per annum. Likewise, the growth of power demand in the residential sector was 7.3%, whereas the growth in the industrial sector demand was the lowest among the sectors and ended up at a mere 4.9%. It is a characteristic trend of recent years that the residential and commercial sectors are leading the power demand. In addition, within the "Others" category, high growth rates in power demand were registered both by public facilities (9.7%) and by government facilities (8.2%), which shows realistic efforts have been paid in upgrading and expanding public service facilities. Whereas the elasticity of power consumption to GDP equated 1.2 for the period of 2012-2001, such a trend of electricity demand growing in excess of GDP is a characteristically observed phenomenon in emerging countries in their developmental stage.

Meanwhile, according to the information obtained in an interview with the Ministry of Energy and Mineral Resources (MEMR), as of 2013, electricity is in short supply across the nation, particularly in the areas outside of Java Island, causing power failures and restrictions on power usage. Furthermore, since Indonesia being an archipelagic nation has an inherent difficulty in expanding the electricity service coverage, its electrification rate in 2012 remained at 76.6%.

According to the Master Plan of Electricity Supply (RUPTL 2011-2020)[17] formulated by the state-owned power utility, Perusahaan Listrik Negara (PLN), electricity demand in Indonesia will expand to 358 TWh in 2021. Further, the maximum demand of the same year is projected to be 61,750 MW, with a growth rate during the plan period at 8.5% per annum. In terms of regions, the

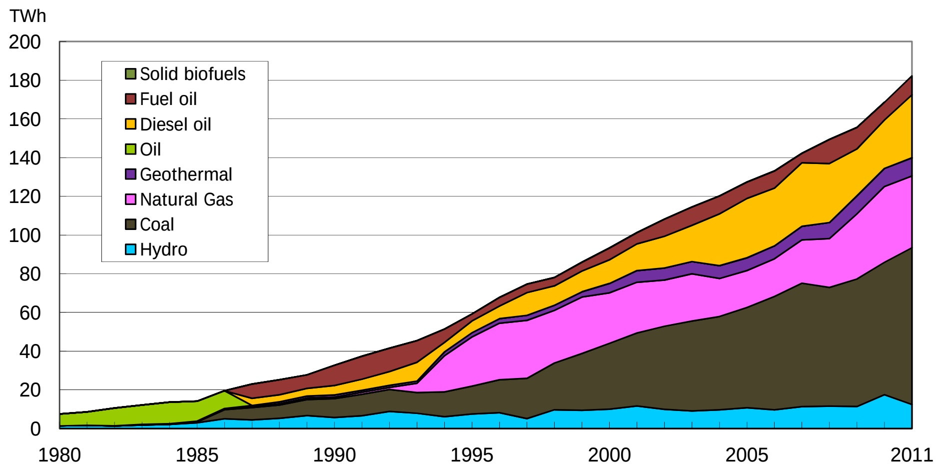
[17] RUPTL is developed by PLN in accordance with the National Electricity General Plan (RUKN) drawn by MEMR.

Java-Bali System as the largest demand center is projected to require 259 TWh in 2021, growing at the rate of 7.9% per annum. The demand in the regions where electrification is lagging will increase at even higher rates and, it is expected that the annual rates of increase will be 11.3% in the eastern region and 10.5% in the western region.

Meanwhile, forecasts by the IEEJ (the forecast previously cited) project a more moderate picture for the future electricity demand to grow at the rate of 5.7% per annum. Even so, it is expected that the power generation output will grow to 310 TWh in 2020, 498 TWh in 2030, and 788 TWh in 2040, nearly reaching Korea's current power generation level (i.e., 520 TWh in 2011), by 2030 or so.

2.2.4 Power Supply

While the amount of power generated in 2012 was 200 TWh, output by the state-run PLN group accounted for 74.8% of the total, with the remainder 25.2% generated by IPPs, private power generation, and others. In the fuel-specific make-up of generated power in 2012, coal-fired thermal power accounted for more than half at 50.3%, followed by 23.4% by natural gas-fired thermal, 15.0% by oil-fired thermal, 6.4% by hydropower, 4.9% by geothermal, and 0.1% by renewables and others. Natural gas-fired and coal-fired thermal power is predominantly operated as the base load source, whereas oil-fired thermal is used as the base load on a limited basis in the remote islands and, in Java, peak adjustment is becoming the primary role of oil-fired thermal power. In Indonesia with so many outlying islands, oil-based power generation (burning either diesel or heavy oil) will remain in use in the future as a convenient means of small-scale power generation.



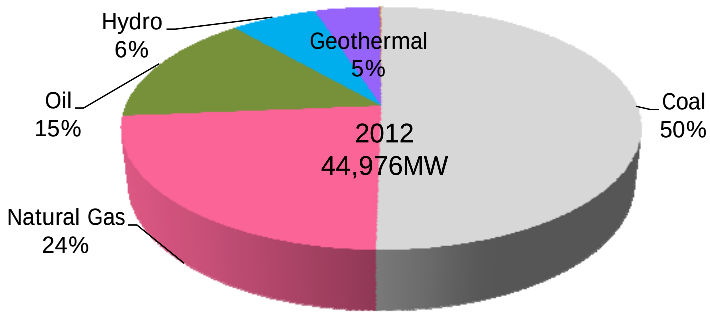
Source: Ministry of Energy and Mineral Resources (MEMR)

Figure 2.2.4 Power Output by Source

According to available power generation results by fuel since 2008, the amount of power generated by coal-fired power increased significantly, growing 1.9 times from 52.3 TWh in 2008 to

100.7 TWh in 2012. On the other hand, oil-fired power is decreasing year by year due to rising fuel costs and other causes, and the amount of power generated by oil-fired power in 2012 decreased to 30.0 TWh or almost one-half of 2008. Although the power output by natural gas-fired thermal power increased, its pace of increase is slower than that of its coal-fired counterpart. This may be indirectly attributed to the difference in fuel costs, but more directly related to the situation where the natural gas supply capacity via pipelines from the existing gas fields in the Java-Bali System is nearly at its upper limit but the new supply system based on LNG has begun only recently. According to the Indonesian government plans, the share of coal-fired power in the over-all generation output will increase further in 2013 to reach 55.2%, whereas the shares of natural gas, oil-based power, and hydropower will all decline.

The installed generating capacity in Indonesia stood at 44,976 MW in 2012, of which coal-fired power accounted for the largest share of 50.3%, followed by natural gas-fired power at 23.4%, oil-fired power at 14.9%, hydropower at 6.4%, geothermal at 4.9%, and others at 0 .1%.



Source: Ministry of Energy and Mineral Resources (MEMR)

Figure 2.2.5 Power Generation Capacity in 2012

The historical development of power generation facilities in Indonesia by form of ownership is as shown in Table 2.2.2 below. While power generation capacity belonging to the state-run PLN increased by 50% during the period of 2004 to 2012, as the company faced funding or other problems, participation of IPPs progressed significantly and the installed capacity owned by IPPs increased 8-fold from 1,285 MW in 2004 to 10,303 MW in 2012. PLN's installed capacity accounted for more than 80% of the total in 2004, but dropped to 73% in 2012. By contrast, the IPP-owned generating capacity reached as high as 23% of the total. It can be said that, in recent years, IPPs have made a major contribution to the expansion of power supply capacity in Indonesia where the increase in power demand continues.

According to the same data by the MEMR, during the period of 2006 to 2012, generating capacity in Indonesia increased by 2,413 MW in an annual average and 14,477 MW in total. As the total investment in the power plant during this period was US$20,295 million, a simple arithmetic indicates that the amount of investment per kilowatt was US$1,402.

Table 2.2.2 Installed Capacity Expansion and Investment

	Capacity (MW)				Investment
	PLN	IPP	PPU	Total	Million $
2004	21,302	3,589	1,285	26,176	n.a.
2005	22,346	3,592	1,303	27,241	n.a.
2006	23,355	5,012	1,321	29,688	2,662
2007	23,664	5,835	1,354	30,853	1,509
2008	24,031	6,017	1,414	31,462	2,884
2009	24,366	6,179	1,414	31,959	4,322
2010	26,338	6,197	1,448	33,983	3,417
2011	30,529	7,653	1,704	39,886	1,671
2012	32,133	10,303	1,729	44,165	3,832

Source: Ministry of Energy and Mineral Resources (MEMR)

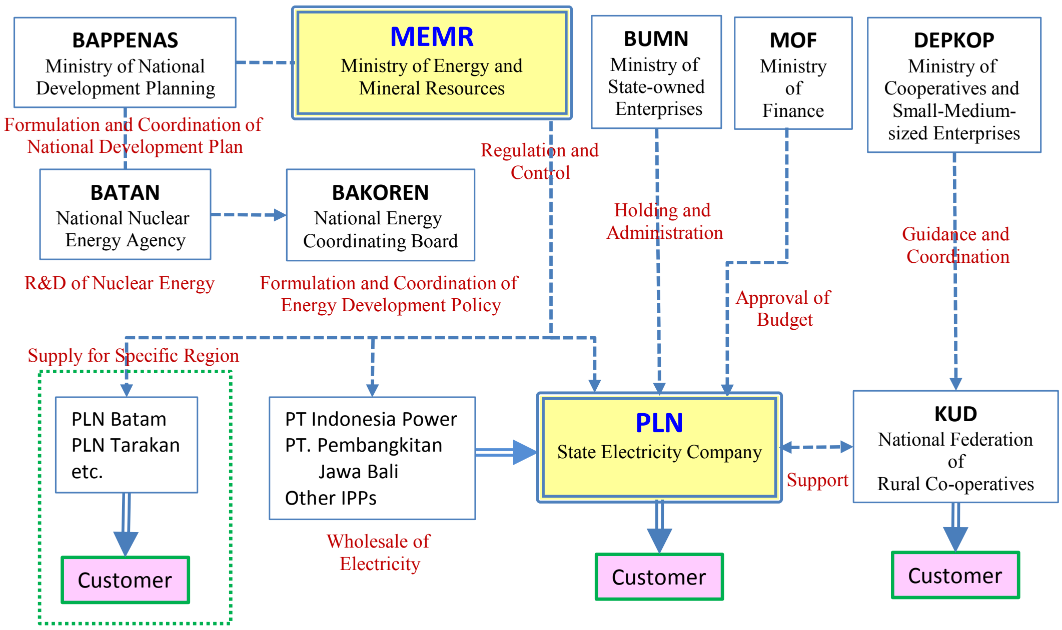
Source: MEMR, "Country Brief of Indonesia", presented at "Energy Sector Reform Workshop", Manila, Philippines, Sept. 2013

Figure 2.2.6 Geographical Distribution of PLN Power Facilities

As of July 2013, the total power generation capacity in Indonesia was 44,976 MW, the total length of transmission lines was 39,114 km, and the total extended distance of distribution lines was 679,258 km. Viewed from a regional perspective, as shown in Figure 2.2.6, Java-Bali System (JAMALI) with the largest concentration of population accounted for 72% of the total generating capacity, which is followed by Sumatra at 17%, with the two regions combined accounting for almost 90%. The same two regions put together also account for about 80% of the national transmission and distribution facilities. The above could suggest that the nature of the issues to be considered in terms of selection or scale of power generation or transmission/distribution facilities may significantly differ between the above two regions and other regions.

2.2.5 Power Utility Systems

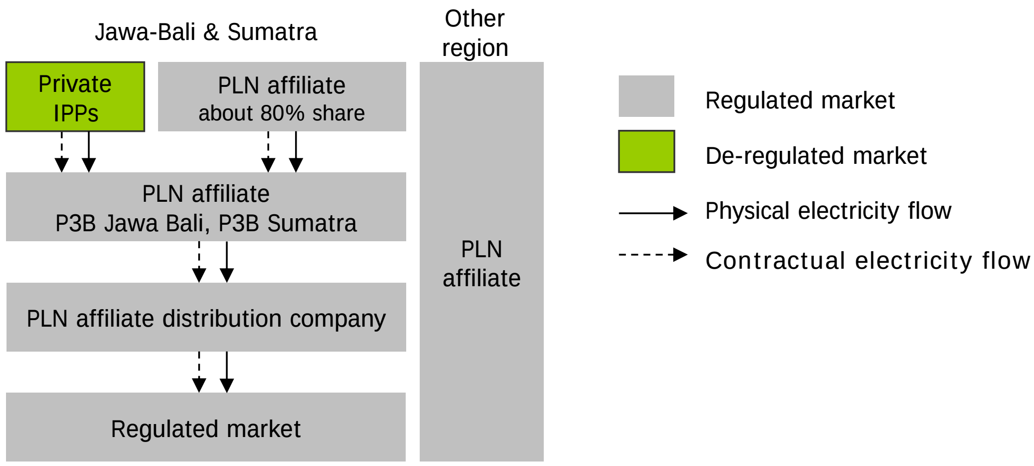
The Indonesian energy sector is regulated by the Ministry of Energy and Mineral Resources (MEMR), which is responsible for all matters concerning natural resources and energy. For the power sector, the MEMR is tasked with overall planning and regulations related to supply/demand plans, power supply infrastructure development plans, as well as promotion of energy conservation and renewable energy. Under the supervision of MEMR, the state-owned utility, Perusahaan Listrik Negara (PLN), is charged with the power supply activities covering the entire nation. In addition, as shown in Figure 2.2.7, the Ministry of State-Owned Enterprises that owns and manages PLN, the National Nuclear Energy Agency (BATAN), the Ministry of Finance (MOF) to approve budget, the village unit cooperatives (KUDs) promoting electrification in rural areas, etc. are involved in the electricity business other than MEMR.



Source: Japan (METI) Report: http://www.meti.go.jp/meti_lib/report/2012fy/E002962.pdf (in Japanese)

Figure 2.2.7 Power Utility System in Indonesia

Since 1995, PLN has been working gradually on separation of power transmission business or divestiture of power generation business, but still the nature of the corporation as a vertically integrated entity has not fundamentally changed, and deregulation that has so far taken place was only in the power generation sector as shown in Figure 2.2.8. Although the entry of IPPs was allowed for the first time in Indonesia, in 1992, a system was then established where all of the power produced by IPPs should be sold to PLN through competitive bidding, with exception of quantities that have acquired MEMR's permission for direct sales to specified customers. Nevertheless, as discussed earlier, the IPPs have played a major role in the power supply capacity expansion in Indonesia.



Source: Prepared by IEEJ from PLN and other data

Figure 2.2.8 Power Market in Indonesia

2.2.6 Power Tariff and Subsidies

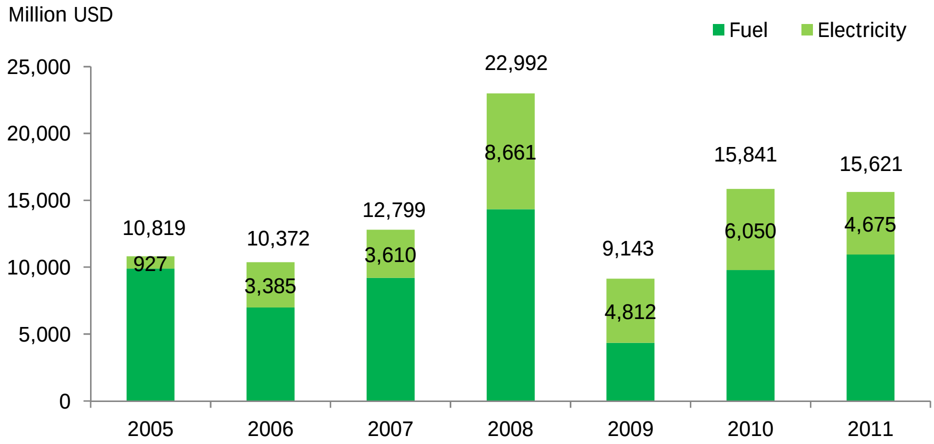
The average electricity prices in Indonesia in 2012, when converted into U.S. dollars, were 6.7 US¢/kWh for residential users, 10.3 US¢/kWh for commercial users, and 7.6 US¢/kWh for industrial users, with an aggregate average being 7.8 US¢/kWh. As commonly seen in developed countries, retail electricity prices for residential use are usually higher than those for other uses such as industrial sector, but in the case of Indonesia, household use is set at the lowest rate. Because of this, the ratio of the government subsidy (paid to PLN) to the full rate approaches to about 20% in the case of small residential users with an electricity contract of 900 watts (VA) or less. Endowed with rich domestic energy resources, Indonesia has been able to keep oil and electricity tariffs at low levels for decades, and it appears that doing away with such practices may be difficult for the moment.

Table 2.2.3 Electricity Prices by Use Category

Cent/kWh	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	6.24	5.80	6.24	6.25	6.06	5.67	6.78	7.05	6.73
Industrial	6.26	5.87	6.82	6.80	6.41	6.20	7.27	7.93	7.56
Business	7.63	7.16	8.34	8.45	8.77	8.57	10.28	10.84	10.28
Social	6.36	5.87	6.39	6.28	6.09	5.56	6.86	7.37	7.22
Gov.Office Building	7.97	7.53	8.25	8.13	8.73	8.38	10.48	10.72	10.32
Publ. Street Lighting	7.15	6.48	7.04	7.09	6.86	6.38	8.20	9.02	8.55
Average	6.51	6.09	6.86	6.88	6.73	6.45	7.69	8.14	7.76

Note: Due to exchange rate factors, although the 2012 prices appear lower than the 2011 prices in dollar terms, they actually rose in local currency terms.
Source: PLN Statistics

The Indonesian government subsidizes electricity prices disbursed from the government budget. In recent years, although electricity prices have been raised year by year, they are still below the total cost covering power generation, transmission and distribution, and profits of power utilities. Because any electricity rate hike needs an approval by the People's Representative Council (DPR), legislators, being conscious about voting public, tend to take a cautious stance for an increase in electricity rates. For this reason, a system is established where the government is to compensate for the portion of deficit calculated on the basis of statements of cost and profit as submitted by power utilities, and in reference to the predetermined profitability criteria for the electric power industry. According to the relevant statistics of Indonesia, government subsidies paid to power utilities in 2011 amounted to US$4.68 billion, and equated to as much as 5.5%of GDP in Indonesia of the same year. While MEMR has drawn up a roadmap for significantly reducing subsidies by increasing electricity prices to a level sufficient to cover the actual cost, with targeted implementation by 2015, whether the plan can be carried out as desired is unpredictable.



Source: Statistical Yearbook of Indonesia, 2012

Figure 2.2.9 Government Expenditure on Energy Subsidies

2.2.7 Power Generation Cost

According to the PLN statistics, the average cost of electricity generation in 2012 was about 13 US¢/kWh in U.S. dollar terms as shown in Table 2.2.4, of which fuel costs averaged at 11 US¢/kWh and accounted for more than 80% of the total. With respect to generation cost by energy source, the cost of hydroelectric power was the lowest at 1.7 US¢/kWh. The cost of diesel-based power was the highest at 33.8 US¢/kWh, which is made up of: 72.9% fuel cost, 7.7% maintenance, 5.7% depreciation, and 3.3% labor costs. Diesel generators mainly comprise those initially used for small-scale power generation in rural areas and then gradually integrated into the grids, or those being utilized for peak load shaving, and are inherently expensive from the standpoint of the scale of economy or the capacity utilization.

Meanwhile, the cost of coal-fired thermal power was at 8.6 US¢/kWh and the next lowest to hydroelectric power, in which fuel cost accounted for 77% of the total, with the remainder 23% comprising maintenance, depreciation, and personnel cost, etc. While the generation cost by coal-fired thermal is low, to be sure, there could be a way of viewing it that the actual cost may be higher taking into consideration environmental costs that are not accounted for in here.

Although natural gas-fired thermal power is listed with a high cost of 25.2 US¢/kWh, second only to diesel power generation, it is because the mainstay of the current fleet is old and of outdated design with low efficiency. For reference, power generation cost of a state-of-the-art combined cycle gas turbine generator is less than half the above. Geothermal power is also a low-cost power source, but fuel costs (i.e., steam procurement costs) account for 90% of the cost, making development of efficient geothermal resources a key. As coal-fired thermal and geothermal power plants are operated in the base load mode, it may have an impact on the generation cost calculation.

Table 2.2.4 Power Generation Cost at PLN (2012)

	Fuel	Maintenance	Depreciation	Others	Personnel	Total
			Cent/kWh			
Hydro	0.2	0.3	0.9	0.0	0.2	1.7
Coal	6.7	0.7	1.2	0.0	0.1	8.6
Diesel	24.6	5.9	1.9	0.2	1.1	33.8
Natural Gas	22.8	0.7	1.5	0.0	0.1	25.2
Geothermal	10.8	0.2	0.8	0.0	0.2	11.9
Combined Cycle	9.4	0.5	0.7	0.0	0.0	10.7
Average	11.0	0.7	1.1	0.0	0.1	13.0
			%			
Hydro	13.7	19.8	52.4	2.6	11.6	100.0
Coal	77.3	7.7	13.9	0.2	0.8	100.0
Diesel	72.9	17.6	5.7	0.6	3.3	100.0
Natural Gas	90.4	2.8	6.2	0.1	0.5	100.0
Geothermal	90.6	1.5	6.3	0.2	1.4	100.0
Combined Cycle	88.3	4.4	6.6	0.3	0.4	100.0
Average	85.2	5.5	8.2	0.2	0.8	100.0

Source: PLN Statistics

Based on the data tabled above, Figure 2.2.10 was prepared to illustrate the relationships between the power generation cost, electricity prices, and subsidies. It can be seen in the graph that, in recent years, against the upward trends of power generation cost reflecting the escalation in fuel prices, electricity prices remained almost unchanged, and the ratio of subsidies is climbing as a result.

While MEMR has drawn up a roadmap for the implementation of electricity prices that reflect the actual cost and the reduction of subsidies, issues such as whether effective measures, for example, a trump card called “LPG conversion” used in the case of the reduction of kerosene subsidies will become available, or how to deal with consumers of less than 1 KW in electricity demand with a particularly high subsidy ratio will be a subject of future investigation.

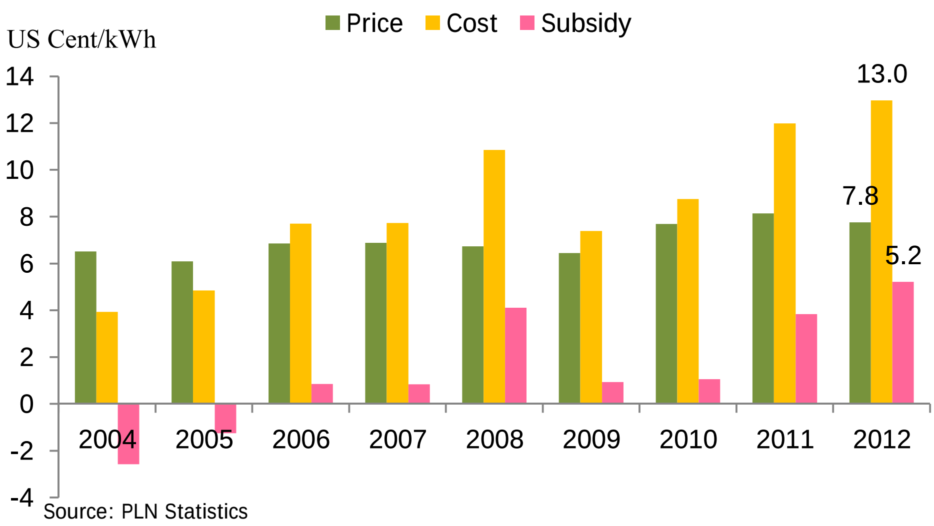


Figure 2.2.10 Historical Power Cost/Price/Subsidy Relationships

2.2.8 Power Development

The Master Plan of Electricity Supply (RUPTL) projects that power generation capacity will more than double from 199 TW in 2012 to reach 411 TW in 2021, with an assumed average growth rate of 8.4% per annum.

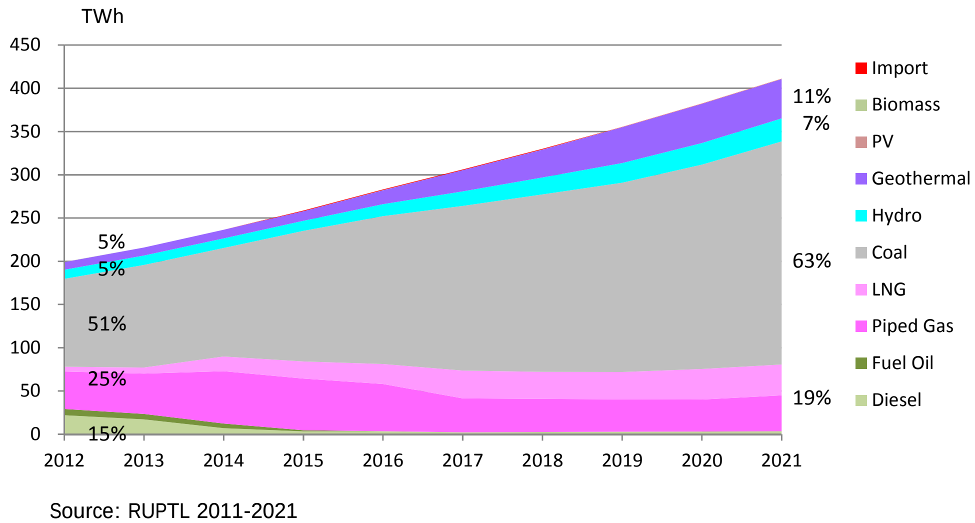


Figure 2.2.11 Power Mix in Indonesia

In the above plan, it is intended to significantly reduce oil-based power generation by around 2015, and advance the power development programs with a focus on coal and natural gas. Although it is planned to increase geothermal power generation to 5 times the current level by 2021, and likewise hydropower to 2.5 times, and solar power to 23 times, the majority of the increase in power supply will necessarily continue to rely on fossil fuels. As a result, coal consumption for power generation will significantly increase from 51.23 million tons in 2012 to 134.4 million tons in 2021, while natural gas consumption will also increase from 434 Bcf to 599 Bcf, in which the ratio of LNG will rise to 44% from 11%. On the other hand, oil consumption is planned to be reduced drastically from 9.06 million KL to 1.01 million KL.

Meanwhile, according to the IEEJ (the forecast previously cited), Indonesia's power generation output will increase from 182 TWh in 2011 to 310 TWh in 2020, 498 TWh in 2030, and 788 TWh in 2040. In terms of power mix, while the share of hydroelectric power is projected to decrease gradually due to resource constraints, where coal and natural gas will support the power supply, the natural gas-fired thermal power is likely to play a role for the reason of CO_2 emissions reduction. Note that the above-mentioned forecast does not cover the subject of nuclear power generation.

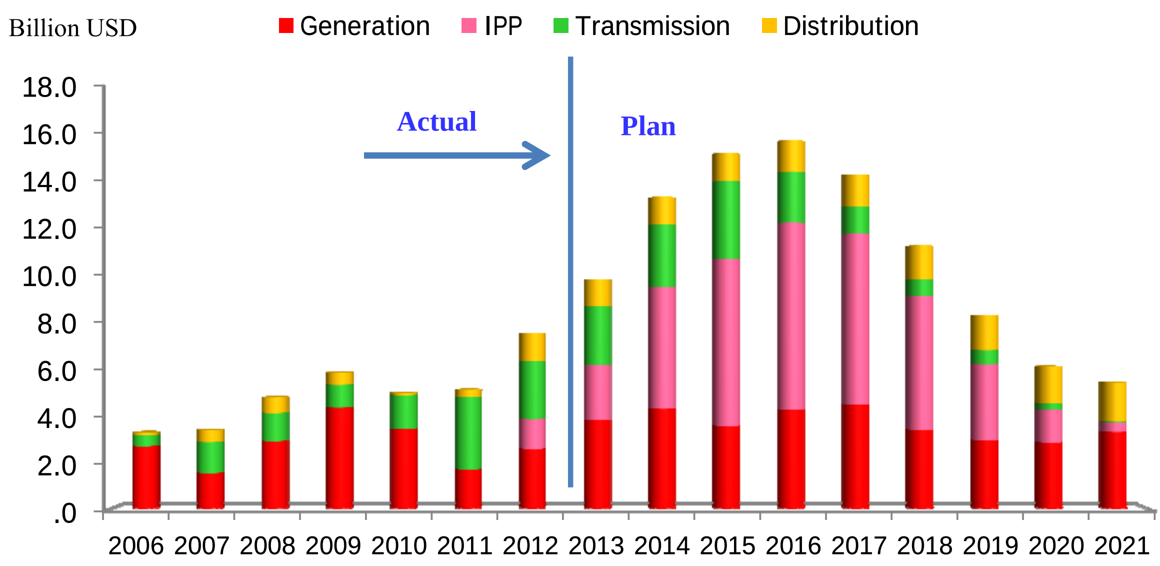
According to the above Master Plan, Indonesia's total power development investment during the period of 2013-2021 will amount to US$99.6 billion, in which investment in power generation facilities, at US$73.5 billion, account for almost three quarters of the total. Likewise, US$13.5 billion will be needed for the deployment of transmission lines, and US$12.6 billion for the distribution lines. As shown in Figure 2.2.11, investment in power generation facilities stands out distinctively at US$ 8.2 billion per year for the plan period at this time, or about three times the US$2.9 billion per year recorded during the period of 2006-2012. Above all, it is projected that the intensive investment by IPPs will significantly push up the power generation investment during the period of 2013-2019, and, as a result, 56% of total investment in power generation facilities during the period of 2013-2021 is to be made by IPPs.

Table 2.2.5 Estimated Power Generation Output

	Power Generation (TWh)				Composition (%)			
	2011	2020	2030	2040	2011	2020	2030	2040
Coal	81	154	276	472	45	50	55	60
Oil	42	39	37	34	23	13	7	4
Natural Gas	37	75	122	197	20	24	24	25
Nuclear	-	-	-	-	-	-	-	-
Hydro	12	14	16	17	7	5	3	2
Geothermal	9.4	27	47	67	5	9	9	9
NRE	0.2	0.4	0.7	1	0	0	0	0
Total	182	310	498	788	100	100	100	100

Source: IEEJ Asia/world Energy Outlook 2013

Although investment in transmission lines will remain nearly flat at US$1.5 billion per year in average, expenditure for power distribution systems is almost tripling from US$500 million to US$1.4 billion per year. In Indonesia, rural electrification is being promoted by the national budget and expansions of distribution facilities are under way with the goal of raising the Electrification Rate to 80%, and the Village Electrification Rate to 98.9% by 2014. As enormous capital expenditure is needed to upgrade and expand the power sector, but the funding capability of the state-run PLN is limited under the circumstances where electricity prices fall below the cost, much is expected of support from the national budget as well as IPPs.



Source: PLN, Master Plan of Electricity Supply (RUPTL)

Figure 2.2.12 Capital Expenditure Plans

2.2.9 International Power Grid interconnection

In ASEAN, an international interconnection concept called an "ASEAN Power Gird" to link the member countries such as Indonesia, Malaysia, the Philippines, etc., has been under consideration, which will be discussed more in detail in Section 2.4. While it appears that some more time will be required to lay out a framework for the specific implementation plans, as trunk transmission lines in respective ASEAN countries are expanded, a plan will come to gradually take shape along with the progress of the integration of the ASEAN economy. The international power grid interconnection projects which just began between Indonesia and Malaysia will be able to kick off such initiatives.

Presently, although there is a location in West Kalimantan where transmission lines are partially connected between Malaysia and Indonesia, the amount of power transmitted is very small[18], and transmission is often interrupted depending on seasonal or other demand fluctuations in the Malaysian side. Further, although Malaysia's transmission system development plans up to 2017[19] does not mention any project for international link with Indonesia, the Indonesian side does have international grid interconnection plans, as shown in Figure 2.2.6, such as the above-mentioned project in West Kalimantan and another one at a location across the Straits of Malacca.

On the Malaysian side, Unit No.1 of the Bakun Hydropower Project, which is a large-scale

[18] Malaysia/External Trade Statistics System, Indonesia/BPS-Statistics Indonesia (http://dds.bps.go.id/eng/)

[19] Malaysia Energy Commission, "Electricity Supply Industry Outlook 2013"

hydropower development project located inland Sarawak, started operation in 2011, and there also is a plan for power transmission of 50 MW (200 MW in the future) to West Kalimantan starting from 2015. If there is sufficient demand in the Indonesian side, the transmission capacity could be increased. However, since the current Indonesian law prohibits substantial dependency on imported power supply, further increase will need proper development of legislation. Although the Bakun Project (see Box) is a large hydropower development originally launched with an eye on power transmission to Peninsular Malaysia, the supply to West Kalimantan appears only natural. Besides, from the point of its location, this project will in the future provide a core project that forms the east side corridor as a part of the ASEAN Power Grid, starting from Indonesia and Malaysia and leading to the Philippines.

In addition, a project for interconnection between Sumatra (Riau) and Malay Peninsula (in the vicinity of Kuala Lumpur) has also been proposed in PLN's plan. This is a plan to reciprocate relief supplies by making use of the difference in peak demand time of the two countries (i.e., Sumatra peaks at night; Malaysia in the daytime), where an undersea cable is used for power transmission. Further, another project is also under consideration to export electricity produced by minemouth generation utilizing lignite in South Sumatra to Malaysia, but this does not go much beyond a conceptual stage as yet. If Malay Peninsula and Sumatra are connected with transmission lines, it could form one end of the west corridor of the ASEAN Power Grid, going through Malaysia and leading to Thailand, Laos, and Vietnam.

<u>Bakun Hydropower Project：</u>

The Bakun Dam is an embankment dam constructed on the Balui River, an upstream tributary of the Rajang River located in Sarawak, on the Malaysian island of Borneo. It is planned to eventually generate 2,400 MW (8×300 MW) of electricity, and its first phase (300 MW) was completed and brought online in August 2011. In this area, projects are in progress to construct dams on four tributaries upstream of the Rajang River, namely, Pelagus, Bakun, Murum, and Belaga, and to build a large hydropower generation base. The Murum Dam (944 MW) was completed in 2013. The Bakun Project is a large-scale hydropower development originally launched with an eye on power transmission to Peninsular Malaysia. Power generation capacity in Sarawak prior to completion of the Bakun Hydropower was at 1,300 MW, with hydropower accounting for only 8% of the total. With the completion of the giant plant, 80% of the power of the State is to be supplied by hydroelectricity. Electricity produced by the Bakun Hydropower is sold to the local power utility, Sarawak Energy Berhad, for 6.25 sen/kWh (about US¢2/kWh).

2.3 Philippines

Table 2.3.1 Key Indicators

		2011
1) GDP (nominal)	Billion US Dollars	224.8
2) Population (as of 1 July)	Million person	94.2
3) Per capita GDP	US Dollars/person	2,386
4) Total Primary Energy Supply (TPES)	Million tonnes oil equivalent (MTOE)	40.5
5) Energy Self-supply Ratio	-	59.1%
6) Electricity Consumption	Tera WH (TWH)	56.1
7) Power Generation Capacity	Million kW	17.0(2012)
8) CO_2 Emissions (energy origin)	Million tons CO_2 equivalent (Mt-CO_2)	134.6(2010)
9) Per capita Primary Energy Supply	TOE/person	0.429
10) Energy Intensity per GDP	TOE/Thousand USD	0.180
11) Per capita Electricity Consumption	kWh/person	596
12) Electrification rate [2009]	-	79.0%
13) Electricity Intensity per GDP	kWh/Thousand USD	250
14) Per capita CO_2 Emissions (energy origin)	Ton-CO_2/person	1.454(2010)
15) Primary Energy Supply Composition	Coal	20.9%
	Oil	30.7%
	Natural Gas	8.1%
	Nuclear	0.0%
	Hydro	2.1%
	Geothermal	21.1%
	Other Renewables	17.1%
16) Energy Self-sufficiency	Total	59.1%
	Coal	43.0%
	Oil	6.2%
	Natural Gas	100.0%

Source:IEA, ADB, DOE, etc

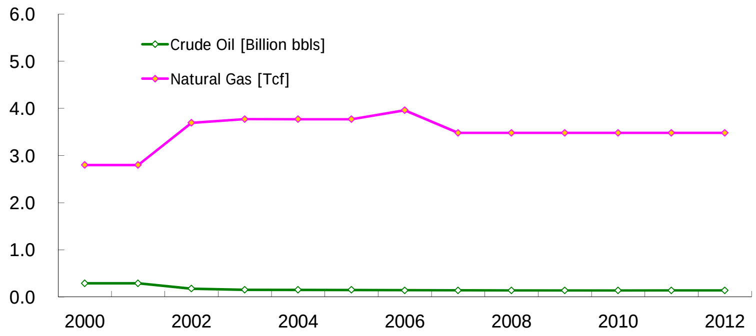
2.3.1 Economic Conditions

The Philippine economy showed a steady growth with an average annual rate of 6.8% for the period of 2012-2013. According to IMF's "World Economy Outlook 2013", the Gross Domestic Production (GDP) of the country was US$250.2 billion in 2012, and with the population of 96.71 million, per capita GDP was US$2,587. In terms of sector make-up, the proportion of primary, secondary and tertiary industries in its GDP was 10.5%, 33.2%, and 56.4%, respectively. The Philippine economy is booming more recently, driven mainly by urban development, and recorded an annualized rate of growth at 7.5% in the first half of 2013. While the IMF predicts a 6.0% growth for 2014 and an average annual rate of 5.5% for the period of 2012-2018, possibilities of attaining even healthier growth are being discussed.

Concerning the ultra-long-term economic outlook of the Philippines, the IEEJ (previously cited), has predicted average annual rates of growth during the periods of 2011-2020 at 5.4%, 2020-2030 at 4.7%, and 2030-2040 at 4.1%, respectively, based on the assumption of growth at approximately the same level as with the IMF.

2.3.2 Energy Supply and Demand

The Philippines is not endowed with particularly abundant energy resources, with flagship assets being the Camago-Malampaya gas field in offshore Palawan Island and the Semirara coal mine located on a small island about 300 km south of Manila. Although the DOE is earnestly working on exploration of oil and natural gas, the effort has not resulted in outcomes to satisfy its ambitious goal. Because the Semirara coal has strong alkalinity, which is detrimental to boilers, it needs to be burnt with imported coal at roughly 70% in ratio and, consequently, it has a limited outlet. For this reason, a part of the production began to be directed to export since 2007. Following the commissioning of a new coal-fired power plant in Mindanao in 2006, the domestic coal production began to increase. Since the proven reserves of domestic coal are only 440 million tons, unless there is significant discovery and development of new resources in the future, the current production pace of 7 million tons per year might prove to be a little greater than the optimum rate.

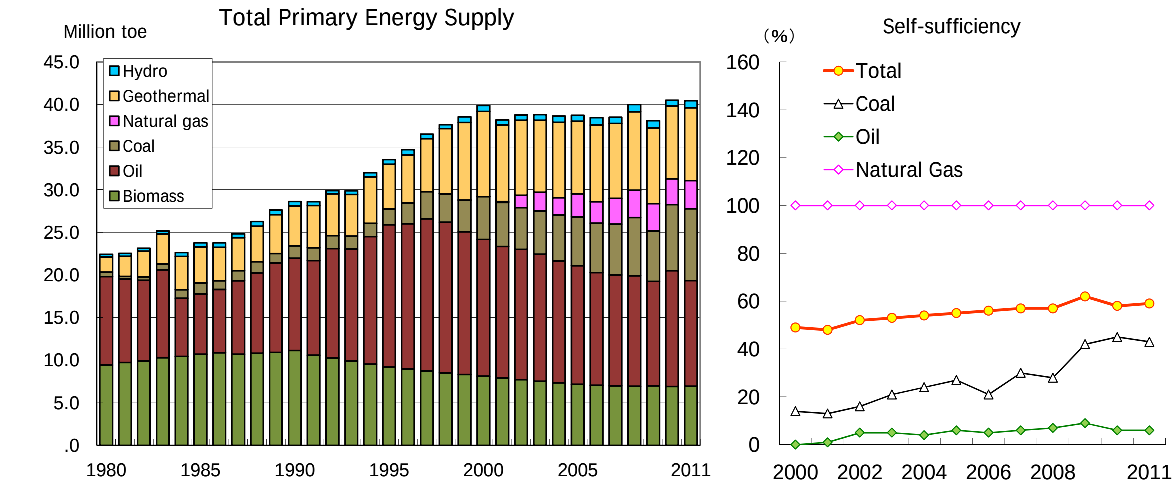


Source: BP Statistical Review of World Energy, 2013 Edition

Figure 2.3.1 Energy Resources of the Philippines (Proved Reserves)

Even though the Philippine economy has registered a reasonable growth of 4.7% per annum since 2000, its energy demand has stayed almost flat at about 40 million tons of oil equivalent (MTOE) per year as shown in Figure 2.3.2. However, energy demand has turned to increase more recently, registering an increase of 3.3% in 2011, and 4.7% in 2012. It would be necessary to watch carefully the future trend since it appears a new development may be taking place in the energy demand picture along with the economic upturn.

The Philippines produces coal, natural gas, geothermal energy, and a small quantity of crude oil. In the last few years, increased production of domestic coal has been raising the energy self-sufficiency rate. Meanwhile, the Malampaya gas fields that provide nearly 30% of the nation's power production have already reached a plateau production stage and, if there is no sizable discovery in the future, it is difficult to maintain the current level of production or to raise the consumption rate. Under these circumstances, plans to build LNG import terminals in the Bataan Peninsula and Batangas City near Metro Manila are being investigated.



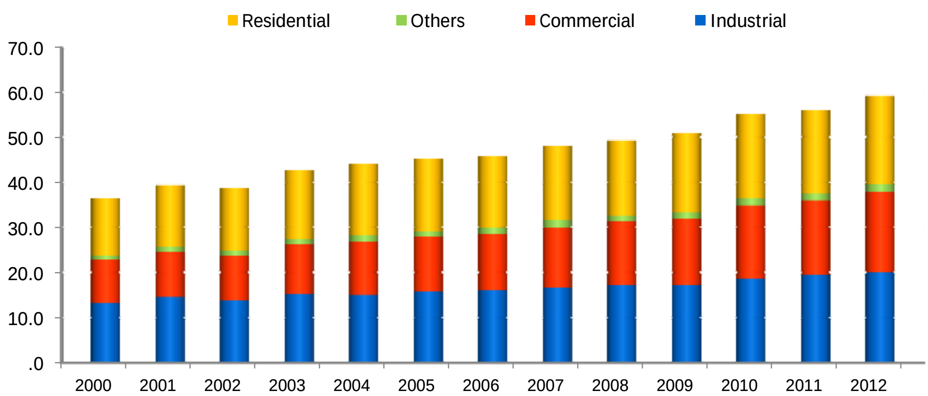
Source: Energy Balances of Non-OECD Countries 2013, IEA

Figure 2.3.2 Primary Energy Supply in the Philippines and Self Sufficiency Rate

According to the prediction by the IEEJ (previously cited), energy consumption in the Philippines will track a growth path of about 3% per annum from now on, and is expected to reach 49 MTOE by 2020, 66 MTOE by 2030 and 87 MTOE by 2040. The development of geothermal energy, another domestic energy source, will also advance to some extent. However, since available resources are not so plenty, it is expected that the increase in imports of oil, coal, or natural gas, etc. will be needed to support the growing energy demand in the future.

2.3.3 Power Demand

According to the Philippine Department of Energy (DOE) statistics, final electricity consumption in the Philippines was 59.2 TWh in 2012, showing an average annual growth rate of 3.9% over 45.1 TWh in 2005.

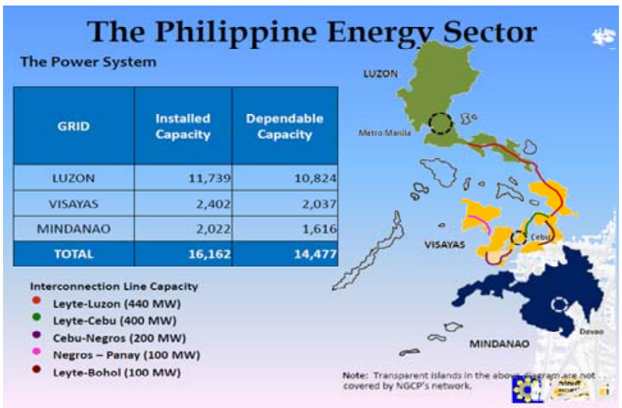


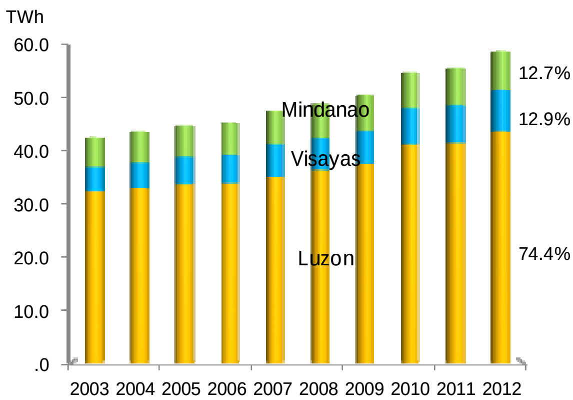
Source: The Philippine DOE

Figure 2.3.3 Power Demand in the Philippines

In contrast with the energy consumption in the Philippines for the last 10 years, which has remained almost unchanged, its power demand has been increasing steadily. The growth rate registered from 2010 to 2012 was 7.1% per annum, but the increase has accelerated more recently. In terms of consumption by sector, final consumption in the industrial sector was 20.1 TWh (accounting for 33.9% of the total), followed by the commercial sector at 17.8 TWh (30.0%), the residential sector at 19.7 TWh (33.3%), and others 1.7 TWh (2.8%). The average annual rates of growth from 2005 to 2012 in power consumption in each of the sectors mentioned above were 3.6%, 5.5%, 3.0%, and 5.1%, respectively, in which the tendency of the commercial sector leading the growth in power demand is becoming more prominent in the period of 2010 to 2012

As the Philippines is made up of many islands, its power system is broadly divided into three independent grids of Luzon, Visayas, and Mindanao, with the Visayas grid further divided into several independent sub-grids such as Palawan. The Visayas region is rich in geothermal resources but has a limited demand size; on the other hand, Mindanao is suffering from unstable power supply due to lack of reliable power generation facilities. At present, the Luzon grid and the Visayas grid are linked through an interconnection line capable of handling 400 MW. The DOE has a further plan to (a) expand the transmission capacity between Luzon and Visayas, and (b) to connect grids between Visayas and Mindanao. Further, in order to reduce the non-electrified population, various projects are being undertaken including the assistance for non-electrified areas as funded by the Universal Charge (i.e., a specialized charge item to be added in electricity bills), strengthening of transmission and distribution systems, and enhancement of interconnection capacity among sub-grids.





Source: DOE Power Statistics, Presentation on "Investment Opportunities in the Philippine Energy Sector", by DOE Secretary Petilla at Oct. 2013 Symposium in Tokyo

Figure 2.3.4 Power Systems & Power Demand by Grid

Looking at the 2012 demand picture by grid, the demand in the Luzon grid which covers the area accounting for 67.0% of the Philippine economy, 56.7% of the population, and embraces Metro

Manila was 44.1 TWh and accounted for 74.4% of the total demand. Power demand in the Visayas grid was 7.6 TWh with a 12.9% share and in the Mindanao grid with a wide land expanse but less population, the demand was the smallest at 7.5 TWh and a 12.7% share. In terms of rate of demand growth during the period from 2005 to 2012, Visayas was the highest among the regions at 5.4% per annum, Mindanao remained at 3.0%, and Luzon was 3.9% and at the same level as the national average. In Mindanao, in addition to a severe drought in 2009 through 2010 that drove hydroelectric plants to extremely low capacity utilization, factors such as insecure public order also worked to suppress the growth in electricity demand. While construction of thermal power plants and an interconnection line to the Visayas are planned, it is likely to take some more time to resolve the state of power shortage.

Table 2.3.1 illustrates the sector-wise demand at respective grids in 2012. While the demands for each of industrial, commercial and residential sectors are balanced in the Luzon grid, the share of the commercial sector demand is much lower in other two grids. In other words, the ratio of power consumption by commercial sector in Mindanao and Visayas is likely to go up in the future, and a pattern in which commercial sector drives the power demand as a whole may follow thereafter.

Table 2.3.2 Grid Power Requirement by Sector, 2012

	Luzon	Visayas	Mindanao	National
	Demand (GWh)			
Industrial	14,086	3,032	2,954	20,071
Commercial	14,905	1,426	1,446	17,777
Residential	14,262	2,668	2,765	19,695
Total	43,253	7,125	7,164	57,543
	Share %			
Industrial	32.6	42.5	41.2	34.9
Commercial	34.5	20.0	20.2	30.9
Residential	33.0	37.4	38.6	34.2

Source: DOE Power Statistics

Meanwhile, the IEEJ (in the ultra-long-term prediction previously cited) predicted growth in electricity demand to slow down gradually in the future, to 4.0% in the 2011-2020 period, to 3.7% in the 2020-2030 period, and to 3.2% in the 2030-2040 period. For demand trends, therefore, the IEEJ has a view similar to the prediction in the Power Development Plan (PDP) drawn by the Philippine DOE.

2.3.4 Power Utility Systems

The 2012 power generation results, as summarized in Table 2.3.2, show that coal-fired thermal power produced 28.2 TWh (accounting for 38.8% of the total generation output), followed by natural gas-fired thermal power 19.6 TWh (26.9%), oil-based power (including diesel, oil-fired thermal, etc.) 4.3 TWh (5.8%), hydropower 10.3 TWh (14.1%), geothermal 10.3 TWh (14.1%), and other renewables such as biomass, wind power, and photovoltaic combined at 259 GWh (0.4%).

A grid by grid examination of the above table suggests that, in the Luzon grid, coal- and natural gas-fired thermal power plays a dominant role and provides more than 80% of the total requirement. In the Visayas grid, coal-fired thermal and geothermal together provide more than 90% of the total. In the Mindanao grid, while coal-fired thermal generates 18.5%, and oil-fired thermal 18.8% of the total output, by far the largest source is the hydropower, with annual energy production of 4,913 GWh accounting for 53.8% of the entire output of the grid.

Table 2.3.3 Grid Power Generation by Energy Source in 2012

Source	Luzon		Visayas		Mindanao		National	
	GWh	%	GWh	%	GWh	%	GWh	%
Coal	21,878	41.8	4,701	41.1	1,686	18.5	28,265	38.8
Natural gas	19,642	37.5	0	0.0	0	0.0	19,642	26.9
Oil & Diesel	1,855	3.5	679	5.9	1,720	18.8	4,254	5.8
Hydro	5,292	10.1	46	0.4	4,913	53.8	10,252	14.1
Geothermal	3,588	6.9	5,930	51.9	731	8.0	10,250	14.1
Biomass	37	0.1	71	0.6	75	0.8	183	0.3
Wind	75	0.1	0	0.0	0	0.0	75	0.1
PV	0	0.0	0	0.0	1	0.0	1	0.0
Total	52,368	71.8	11,428	15.7	9,127	12.5	72,922	100.0

Source: DOE Power Statistics

Deducing from the power generation status shown in the above table, in the Visayas and Luzon grids, oil-based power generation has been operated mainly for peak adjustment, but in the Mindanao grid, a part of oil-based generation facility is operated as the base load for reasons related to power transmission capacity or fuel procurement. Further, in the Visayas grid, it seems that coal-fired thermal and geothermal are used as the base- as well as middle-load (load follow up) supply.

Table 2.3.4 Grid Power Mix in 2012

Source	Luzon		Visayas		Mindanao		National	
	MW	%	MW	%	MW	%	MW	%
Coal	4,219	37.2	777	36.9	210	13.0	5,206	34.6
Natural gas	2,759	24.3	1	0.0	0	0.0	2,760	18.3
Oil & Diesel	1,586	14.0	505	24.0	470	29.1	2,561	17.0
Hydro	2,147	18.9	11	0.5	826	51.2	2,984	19.8
Geothermal	587	5.2	777	36.9	98	6.1	1,462	9.7
Others	51	0.4	33	1.6	10	0.6	94	0.6
Total	11,349	75.3	2,104	14.0	1,614	10.7	15,067	100.0

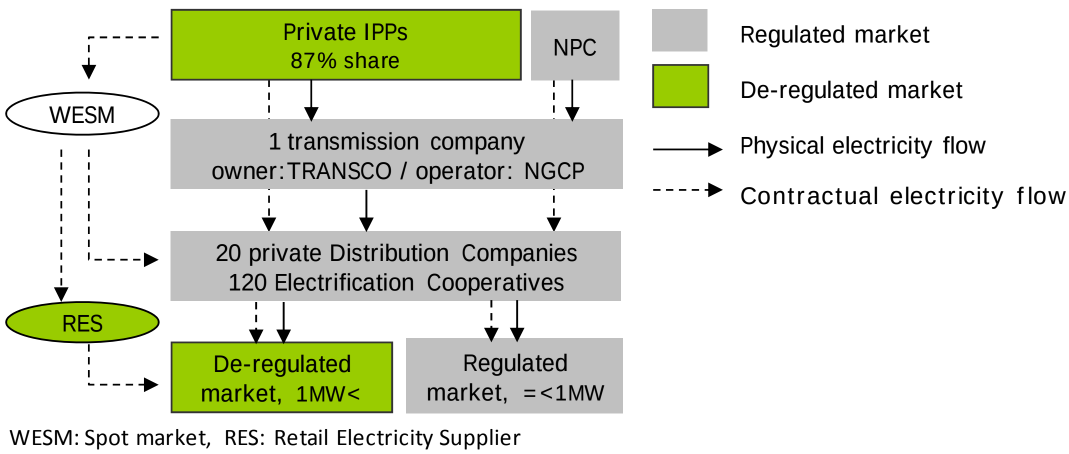
Source: DOE Power Statistics

The total installed generation capacity in the Philippines as of 2012 stood at 17,023 MW. At the top of the line-up, coal-fired thermal power accounted for 32.7% of the total, followed by hydropower at 20.7%, oil-based power at 18.1%, natural gas-fired thermal at 16.8%, geothermal power at 10.9%, and other renewables (biomass, wind power, and PV) combined at 0.9%.

In terms of grid-wise breakdown of the installed capacity, as shown in Table 2.3.3, whereas in the Luzon grid, the share of coal fired-thermal power is the largest and natural gas-fired thermal, hydropower and others are deployed in a well-balanced manner, in the Visayas grid, the shares of oil and geothermal are characteristically high, and so are the shares of oil-based power and hydropower in Mindanao. According to the DOE Power Statistics, the bulk of oil-fired thermal power plants currently in operation were installed during the 1980s and the 1990s, and assuming the life of a typical oil-fired power plant to be 25 years, some of the plants have already reached their retirement age, and by 2015, the majority will exceed their service life. On the other hand, most of the coal-fired power plants are those that were installed in 2000 or later. Although geothermal power plants and hydroelectric power plants were introduced in the 1950s through the 2010s, their service life is much longer than thermal power plants. Biomass power generation facilities are the newest, and all of them were introduced in 2007 or later. In view of the high fuel costs on top of aging equipment, oil-fired thermal plants are expected to phase out relatively early, and to be converted to other power sources such as coal or natural gas, as discussed later.

2.3.5 Electricity Administration System

In the Philippines, the Electricity Power Industry Reform Act (EPIRA) was enacted in June 2001, and a sweeping reform of the power sector was initiated by unbundling and privatization of the industry that had been operated with a central role carried out by National Power Corporation (NPC) up until that time.



Source: Prepared by IEEJ from various data

Figure 2.3.5 Power Market in the Philippines

As part of the privatization program, NPC was prohibited from constructing new power plants and the Power Sector Assets and Liabilities Management (PSALM) was established to manage and divest the power plants owned by NPC. According to the EPIRA Implementation Status Report, the privatization level of the generating facilities previously owned by NPC was expected to reach 86.5%, as of the end of April 2013, moving up from 79.56% at the end of October 2012. The increase was brought about by the then in-progress turn-over of Angat Hydroelectric Power Plant to Korean Water Resources, Inc. (K-Water). Meanwhile, for the IPP contracts, the implementation level remains at 76.85 percent. The PSALM was working on the bid of the remaining unprivatized power plants subject to the policy direction of the government.

The PSALM still needs to privatize a total of 1,913 MW of owned-generating assets, of which 1,014 MW is located in Mindanao mainly comprising the Agus-Pulangui hydro complexes. Those located in Luzon and Visayas are all oil-fired power plants.

In the area of the power transmission business, the relevant assets previously owned by NPC were transferred to the National Transmission Corporation (TRANSCO), and a fully private National Grid Corporation of Philippines (NGCP), which is a joint venture between State Grid Corporation of China and two Philippine investors, is in charge of overall operation of the national electricity grid under a concession contract with TRANSCO. For the retail distribution of power in the Philippines, there are Distribution Utilities (DUs) which are made up with 20 private electricity distributors such as Manila Electric Company (MERALCO) who operates in Metropolitan Manila, and some 120 small scale entities called Electrification Cooperatives (ECs).

As a part of the electricity market reform, the Wholesale Electricity Spot Market (WESM) was created in the main Philippine island of Luzon in 2006 and later expanded to include Visayas in 2010. The DOE has incorporated the Philippine Electricity Market Corporation (PEMC) to operate and govern the WESM, and is now asking the PEMC to look into the possibility of establishing an Interim Mindanao Electricity Market (IMEM). In June 2013, the system of Retail Competition and Open Access (RCOA) started its full commercial application, where an end-user with an average monthly peak demand of 1 MW or larger is given a choice of procuring electricity either through a direct contract negotiated with a power generation utility or by trading in the WESM It is planned to expand the eligibility of RCOA to end-users of 750 kW or more in two years after its initial implementation, and eventually to general residential consumers.

2.3.6 Power Tariff and Subsidies

Electricity prices in the Philippines continued to rise gradually after 2000 and, by 2012, reached a level 2.11 times that of 2000 (in U.S. dollar terms; 2.01 times in PHP terms). The prices shot up in 2008 by 43% in response to the spike in oil prices (in U.S. dollars; 38% in PHP), but went back almost to the previous level in 2009. All the same, electricity prices rose by 6% or more in average over the last 12 years. The electricity prices in the Philippines are nearly at the same level as those in Japan and, compared to other economies in Asia, ranked at the highest group along with Singapore; for Industrial electricity prices, they are even higher than those of Japan.

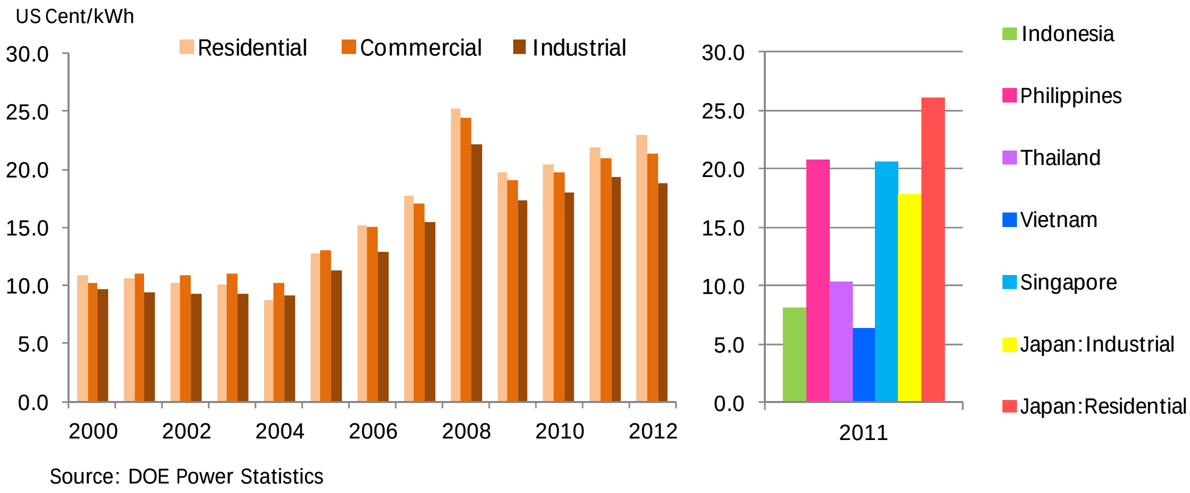


Figure 2.3.6 Electricity Prices in the Philippines and other Asia

2.3.7 Power Cost Analysis

Since there is no official statistics concerning the cost of power generation in the Philippines, an attempt is made to estimate the cost of power supplies in reference to annual reports of major power generation utilities in the Philippines.

According to the 2011 annual report of Aboitiz Power Corporation[20], Cebu, the Philippines, the amount of power output in 2011 was 9,422 GWh, expenditure in its power generation segment (excluding the cost of purchased power) was 20,655 million Philippine Pesos (PHP), while its revenue was PHP54,447 million. Calculating from the foregoing, unit power generation cost equates to 2.2 PHP/kWh (5.1 US¢/kWh), whereas unit electricity selling price was 5.8 PHP/kWh (13.3 US¢/kWh).

Next, according to the 2012 annual report of SEM-Calaca Power Corporation[21], which operates coal-fired power plants as a subsidiary of Semirara Mining Corporation, the largest coal producer in the Philippines, the quantity of electricity sold was 2,025 GWh in 2011 (2,355 GWh in 2012) and the revenue from electricity sale in 2011 was PHP 9,612 million (PHP 9,700 million in 2012), and the unit selling price of electricity by a simple calculation was 4.8 PHP/kWh (10.5 US¢/kWh) in 2011 and 4.1 PHP/kWh (9.7 US¢/kWh in 2012. The quantity of power generated in 2011 was 1,860 GWh and, with the net cost for electricity generation at PHP 5,559 million, the foregoing equates to an average unit generation cost of 2.8 PHP/kWh (6.1 US¢/kWh). The shortfall in

[20] Aboitiz Power has total installed capacity of 2,350 MW comprising 439 MW hydropower, 467 MW geothermal, 844 MW coal-fired and 600 MW oil-fired thermal power plants, altogether accounting for 14.5% of total installed capacity of 16,162 MW in the Philippines as of 2011 end. Its amount of generation output was 9,422 GWh or 5.0% of the national total.

[21] Installed generation capacity estimated at 600MW, and an additional 300MW under construction.

power supply, i.e., 472 GWh, was purchased from outside at an average cost of 3.2 PHP/kWh (7.1 US¢/kWh). From the company's cash flow statements for 2012, it can be seen that the fuel-related costs accounted for 68.0% of the total cost, whereas power purchase cost accounted for 2.7%, maintenance and operation for 6.9%, labor for 3.0%, and others (mostly depreciation and amortization) for 19.4%.

Likewise, looking at the 2012 annual report of Energy Development Corporation (EDC)[22], which operates the world's largest geothermal power plant, electricity sales in 2011 was 6,839 GWh, the revenue from the sales was PHP 24.5 billion, and the unit selling price obtained with a simple arithmetic was 3.6 PHP/kWh (about 8.0 US¢/kWh).

The average power generation cost of the three power generation companies mentioned above was 6.3 US¢/kWh and the average unit selling price was 11.2 US¢/kWh, suggesting that the selling price of each company equates to nearly double the cost of generation.

Table 2.3.5 Cost & Wholesale Price by Power Generation Utilities

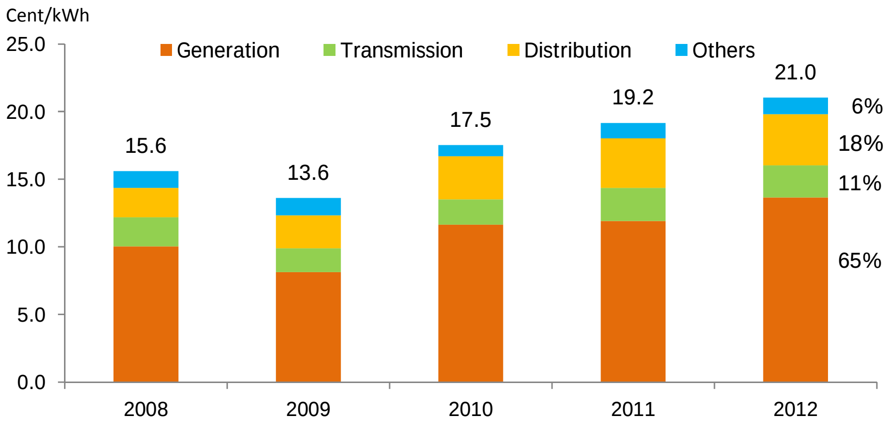
Item	Unit	AboitizPowe	SEM-CALACA	EDC	Average
Generation	GWh	9,422	1,860	-	11282
Purchases	GWh	-	472		472
Sales	GWh	9,422	2,025	6,839	18,286
Revenues	Million Peso	54,447	9,612	24,540	88,598
Expenses	Million Peso	20,655	5,559	4,660	30,875
Cost	Peso/kWh	2.2	3.0		2.7
Price	Peso/kWh	5.8	5.2	3.6	4.8
Exchange Rate	Peso/USD	43.3	43.3	43.3	43.3
Cost	Cent/kWh	5.1	6.9		6.3
Price	Cent/kWh	13.3	11.9	8.3	11.2

Source: Prepared from respective annual reports

Further, according to the annual report[23] of Meralco, the largest power distribution company in the Philippines, the average unit price for procured power in 2012 was 5.6 PHP/kWh (13.6 US¢/kWh), unit cost of power transmission was about 1.0 PHP/kWh, unit cost of power distribution is 1.6 PHP/kWh (7.1 US¢/kWh), and the average retail electricity rate was 8.6 PHP/kWh (21.0 US¢/kWh) including other cost items such as operating losses, for example.

22 http://www.energy.com.ph/

23 http://www.meralco.com.ph/consumer-index.html



Source: Prepared based on respective annual reports of Meralco

Figure 2.3.7 Electricity Cost Breakdown

As discussed above, the analysis based on the annual reports of power producers and power distribution companies in the main market (captive market) reveals that, against the power generation cost of about 6-7 US¢/kWh, the selling prices of power producers often come to as high as 12-13 US¢/kWh, or twice as much as the cost of generation. The above finding leads to a supposition that the main cause of the electricity prices in the Philippines staying at the highest level in Asia could may well be that significant excess profits are maintained at the level of power generation utilities.

In conclusion, it could be pointed out that the main challenge in configuring the power market is how to bring about reasonable and affordable rates of electricity while ensuring the power producers to keep on investing in the facilities required for future expansion.

2.3.8 Power Development Plans

According to the Power Development Plan (PDP 2012-2030) announced by the Philippine government, installed capacity to be newly added by 2030 is 11,400 MW, of which requirement by the Luzon grid accounts for 70% or more. In addition, in the Mindanao grid, where the peak adjustment capability is insufficient even now to cause frequent occurrences of brownout, it is in the condition requiring urgent facility enhancement of 150 MW in 2012, and 50 MW in 2013.

According to the above plan, peak power demand will more than double from 10.9 GW in 2012 and is expected to reach 23.2 GW by 2030. In the grid-wise picture, peak demand in the Luzon grid is projected to increase from 7.97 GW in 2012 to 16.48 GW in 2030 (4.1% in annual average), the Visayas grid, from 1.57 GW in 2012 to 3.43 GW in 2030 (4.4%), and the Mindanao grid, from 1.83 GW in 2012 to 3.77 GW in 2030 (4.8%). With regard to the rate of growth, although the demand in Mindanao is expected to expand slightly faster than other regions, the basic structure will not change wherein three-quarters of the national requirement concentrates in the Luzon grid.

Table 2.3.6 Power Development Plans by Grid

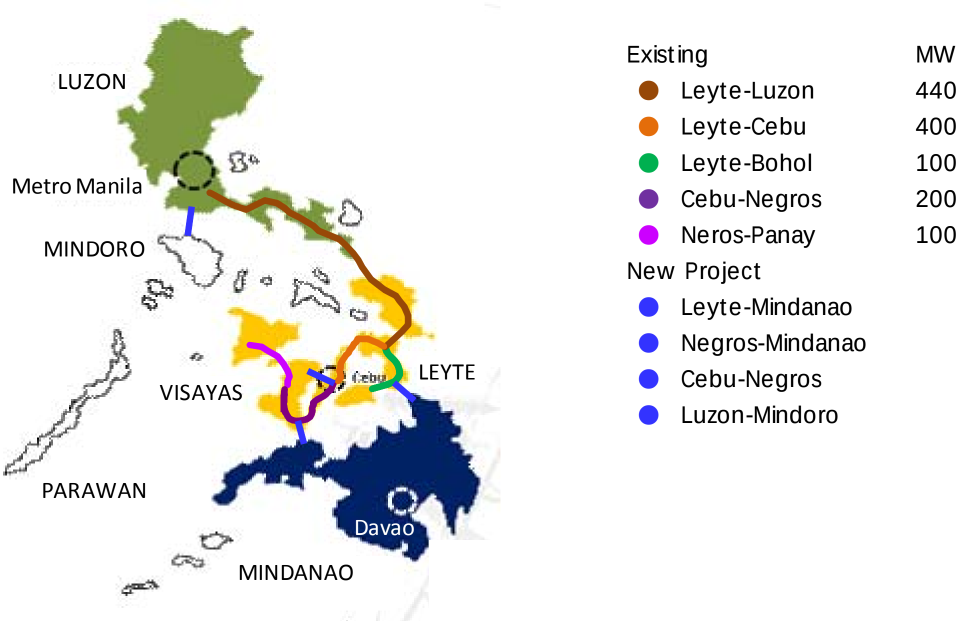
Year	Luzon Grid (MW)			Visayas(MW)			Mindanao(MW)			National(MW)			
	Baseload	Midrange	Total	Baseload	Peaking	Total	Baseload	Peaking	Total	Baseload	Midrange	Peaking	Total
2012								150	150			150	150
2013								50	50			50	50
2014													
2015													
2016	500		500		50	50				500		50	550
2017	500		500							500			500
2018	500		500		50	50	100		100	600		50	650
2019			0	100		100	100		100	200			200
2020	500		500	100		100				600			600
2021	500		500	100		100	100		100	700			700
2022	500		500	100	50	150	100		100	700		50	750
2023		300	300	100		100				100	300		400
2024	500		500	100		100	100		100	700			700
2025	500	300	800	100	50	150	100	50	150	700	300	100	1,100
2026	500		500	100	50	150	100	50	150	700		100	800
2027		600	600	100	50	150	100	50	150	200	600	100	900
2028	500	300	800	100	50	150	100	50	150	700	300	100	1,100
2029	500	300	800	100	50	150	100	50	150	700	300	100	1,100
2030	500	300	800	200		200	100	50	150	800	300	50	1,150
Total	6,000	2,100	8,100	1,300	400	1,700	1,100	500	1,600	8,400	2,100	900	11,400

On the other hand, the above power development plan is based on the assumption that the existing facilities will all be running until 2030 as they are now. However, since most of the oil-fired power plants were constructed in the 1980s through the 1990s, on top of having poor efficiency, it would be impossible for them to serve another twenty or more years. Therefore, the actual capacity to be newly added is likely to be well above the scale that has been laid out in the PDP at this time.

2.3.9 Grid Interconnection

Being an archipelagic nation, the Philippines have had a considerable difficulty in putting a wide area power operation in place through multiple link-ups of regional grids. Although there has been a link established between the Visayas grid of the central region and the Luzon grid, its power interchange capacity is not large enough. Further, the Mindanao grid is not linked with these main grids; elsewhere, relatively large islands of Mindoro and Palawan are also independent grids.

Currently, the DOE is planning to construct (a) the Leyte-Mindanao link, (b) the Cebu-Mindanao link via Negros, (c) the Luzon-Mindoro link, and (d) the link between Cebu and east of Negros. In particular, although it is a pressing issue to complete links to Mindanao under continuing power shortage, despite the stated plans for implementation by or around 2018, specific actions are yet to be observed.



Transparent Islands in the above diagram are not covered by NGCP's network.

Source: DOE Material

Figure 2.3.8 Grid Interconnection – Now and Future

In the future, after interconnections among the main grids are established, it would become possible to introduce efficient large-scale thermal power plants in Mindanao and the Visayas grid with relatively limited scale of demand, on the basis of utilizing exchanges with other grids. Further, geothermal resources available in areas such as Leyte can also be utilized with larger scale designs to contribute to improving the economics.

For international grid interconnection being considered under the ASEAN Power Grid initiative, there are no identifiable movements in specific studies.

2.4 ASEAN

2.4.1 Economic Conditions

According to the Asian Development Bank's statistics (see Table 2.4.1), the total GDP (on a PPP basis) of the ten ASEAN countries in 2012 was about US$3,700 billion, the total population of the ten countries was 613.4 million, and the per-capita GDP was US$6,056. The nominal per-capita GNI was US$3,832. The economic disparities within the ASEAN region are considerably large. Specifically, while the economic situation in Singapore and Brunei was comparable to those of developed countries, the per-capita GNI of Cambodia was less than US$1,000. While the per-capita GNI of Laos, Vietnam, and the Philippines was relatively low, the per-capita GNI of Indonesia exceeded 3,000 USD, and it exceeded US$5,000 in Thailand, where the use of private cars is expected to become widespread. The per-capita GNI of Malaysia approached US$10,000, and former Prime Minister Mahathir's pledge to become a developed country by 2020 is being materialized.

Table 2.4.1 Economic Indicator of ASEAN Countries in 2012

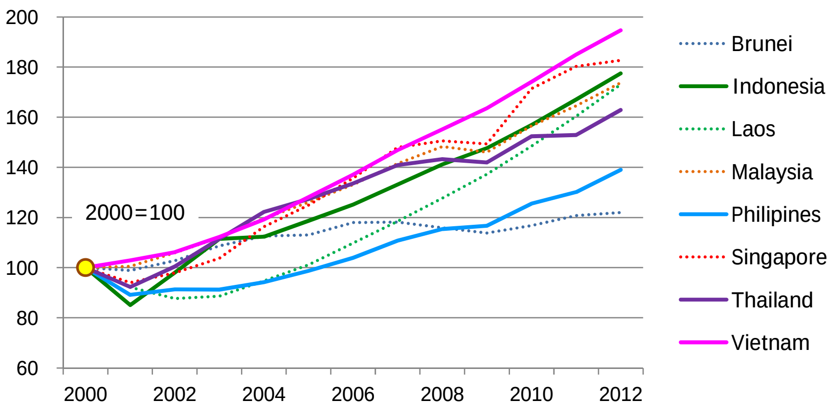
Country	GDP (PPP for 2012)		Population		GDP per Capita	GNI per Capita	Industry Composition		
							Agriculture	Industry	Services
	billion USD	%	Million	%	USD	USD	%	%	%
Brunei Darussalam	22.0	0.6	0.4	0.1	55,007	39,249	0.7	71.1	28.2
Cambodia	37.0	1.0	14.8	2.4	2,505	880	35.6	24.3	40.1
Indonesia	1223.5	32.9	247.2	40.3	4,949	3,420	14.4	46.9	38.6
Lao PDR	19.1	0.5	6.5	1.1	2,925	1,260	27.6	33.1	39.3
Malaysia	501.2	13.5	29.3	4.8	17,084	9,800	10.2	41.2	48.6
Myanmar	109.8	3.0	61.0	9.9	1,801	…	30.5	32.1	37.5
Philippines	426.6	11.5	95.8	15.6	4,454	2,470	11.8	31.1	57.1
Singapore	328.3	8.8	5.3	0.9	61,803	47,210	0.0	26.7	73.2
Thailand	692.3	18.6	64.4	10.5	10,757	5,210	11.4	38.2	50.3
Viet Nam	355.0	9.6	88.8	14.5	3,998	1,400	19.7	38.6	41.7
ASEAN	3714.8	100.0	613.4	100.0	6,056	3,832	12.9	39.5	47.5
Ex. Brunei & Singapore	3364.5	90.6	607.7	99.1	5,536	3,384	14.2	40.6	45.2
Japan	4490.7	120.9	127.6	20.8	35,204	47,870	1.2	26.1	72.7

Source: Asian Development Bank, "Key Indicators for Asia and Pacific, 2012"
(Note: The industrial composition of Thailand and Japan indicates the values in 2011.)

Meanwhile, as shown in Figure 2.4.1, Vietnam with a modest per-capita GNI achieved the highest economic growth (5.6% in average) in the ASEAN region in the 2000s, and its GDP almost doubled in 12 years. Indonesia also achieved a strong growth of 4.4% per annum, whereas the Philippines got a late start, but picked up more recently showing accelerated growth rates from 1.9% (2009 to 2000) to 6.0% (2010 to 2012) in average.

In ASEAN, the income level in the leading economies of Singapore and Malaysia (combined population: 35 million, 6%) has already become comparable to those of developed countries, and the income level in Thailand and Indonesia (311 million people: 51%) has been reaching a level sufficient to spur people to purchase of luxurious consumer goods such as cars. The economy of the Philippines, Vietnam, and Laos (191 million people: 31%) is in a takeoff stage, and it is expected that the dissemination of durable consumer goods will advance accompanying energy consumption. Along with such trends energy consumption in factories for supplies or shopping centers, etc. will increase accordingly. The economic growth rate of Myanmar undergoing political/economic liberalization process reached 13.6% during the period from 2000 to 2012, and Myanmar is expected to join the forerunning group sooner or later.

With regard to industry composition in terms of added value, the service sector accounts for about 50% and the industry sector about 40% of the total. The share of the agricultural sector in Vietnam and Indonesia has become less than 20%, and that in Malaysia, Thailand, and the Philippines is about 10%. In Indonesia, the Philippines, Vietnam, and Thailand with a large population (496 million in total), industrialization and urbanization have boosted economy, and these countries are considered to lead economic growth of ASEAN in the future.



Source: Prepared from ADB, "Key Indicators for Asia and the Pacific, 2012 and 2013"

Figure 2.4.1 GDP Growth Rate of ASEAN Countries (2000=100)

IEA predicts that the annual average GDP growth rate in the ASEAN region during the period from 2011 to 2035 will be 4.6%[24]. The IEEJ, in the forecast previously cited, projects the annual average growth during the period from 2011 to 2040 to be 4.6%. According to the IEA, the worldwide economic growth rate during the period from 2011 to 2035 will be 3.6%, while it will be 2.9% according to the IEEJ projection for the period from 2011 to 2040. It is considered that the ASEAN countries will play a role of an economic engine driving the global economy in the future, together with India (IEA's predicted economic growth rate: 6.3%) and China (IEA's prediction: 5.7%).

[24] IEA, "Southeast Asia Energy Outlook", September 2013

Table 2.4.2 Predicted Annual GDP Growth of ASEAN Countries

	IEA			IEEJ			
	2011-2020	2020-2035	2011-2035	20/11	30/20	40/30	40/11
Indonesia	6.2%	4.2%	4.9%	6.2%	5.0%	4.2%	5.1%
Malaysia	5.0%	3.4%	4.0%	5.1%	4.5%	3.3%	4.3%
Myanmar	-	-	-	6.4%	5.7%	4.3%	5.4%
Philippine	5.6%	4.1%	4.6%	5.4%	4.7%	4.1%	4.7%
Singapore	-	-	-	4.0%	3.0%	1.5%	2.8%
Thailand	4.9%	3.8%	4.2%	4.8%	3.7%	3.0%	3.8%
Vietnam	-	-	-	5.7%	6.4%	4.8%	5.6%
Rest of ASEAN	4.9%	4.4%	4.6%	-	-	-	-
ASEAN	5.5%	4.1%	4.6%	5.5%	4.6%	3.7%	4.6%

Source: IEA and IEEJ

2.4.2 Energy Supply and Demand

The ASEAN countries used to be net exporters of oil and natural gas, but in comparison with the major resource-rich countries of the world, the amounts of resources they own are undersized. Due to the proximity to the main consuming areas, resources have been extracted at a relatively high pace despite their limited size. Although the R/P ratios of coal (lignite) in Thailand and natural gas in Vietnam are relatively high, this is because their outlets are currently limited and, once commercial production moves into high gear, they would be depleted fairly quickly. Since potentials for large scale resources like those found in other regions are not expected from geological point of view, the dependence of ASEAN countries on imported energy is likely to increase gradually.

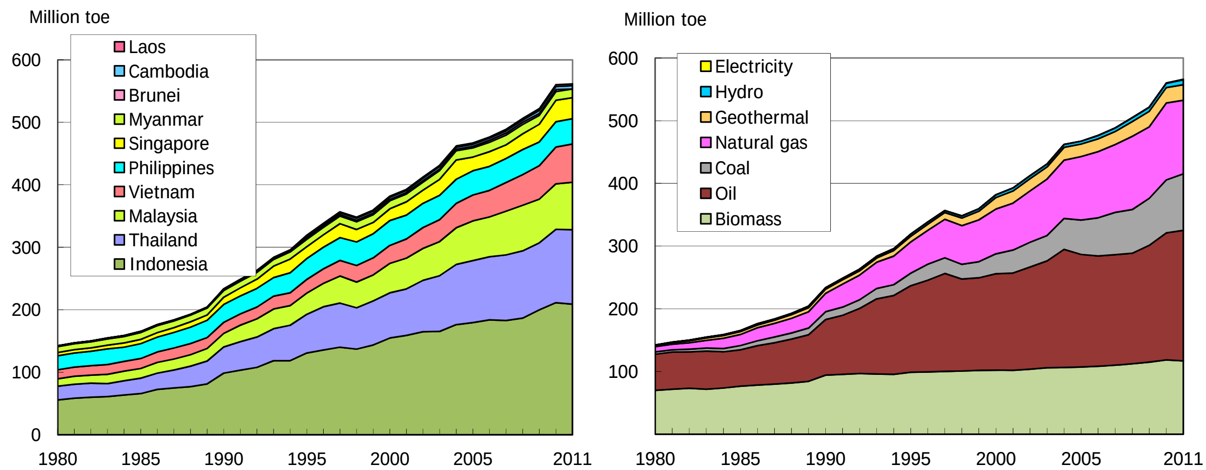
Table 2.4.3 Energy Resources of Major ASEAN Countries

	Oil			Gas			Coal		
	Proved Reserves	Global Share	R/P	Proved Reserves	Global Share	R/P	Proved Reserves	Global Share	R/P
	Million Bbls		Yrs	Tcf		Yrs	Million tons		Yrs
Brunei	1,100	0.1%	19.0	10.2	0.2%	22.9	-	-	-
Indonesia	3,741	0.2%	11.1	103.3	1.6%	41.2	5,529	0.6%	14
Malaysia	3,739	0.2%	15.6	46.8	0.7%	20.3	-	-	-
Myanmar	-	-	-	7.8	0.1%	17.4	-	-	-
Thailand	442	-	2.7	10.1	0.2%	6.9	1,239	0.1%	68
Vietnam	4,400	0.3%	34.5	21.8	0.3%	65.6	150	-	4
Other Asia	1,093	0.1%	10.5	11.8	0.2%	18.6	3,708	0.4%	88

Note: Data for the Philippines included in “Other Asia”
Source: BP, “Statistical Review of World Energy, 2013”

Primary energy demand in the ASEAN countries increased by 4.5% on annual average in the last 30 years, and exceeded 570 million tons of oil equivalent (MTOE) in 2010. Although the average increase rate decreased to 3.6% during the period of 2000 to 2011, the annual increments in terms of absolute quantity actually increased. By regions, the heavily populated Indonesia accounts for

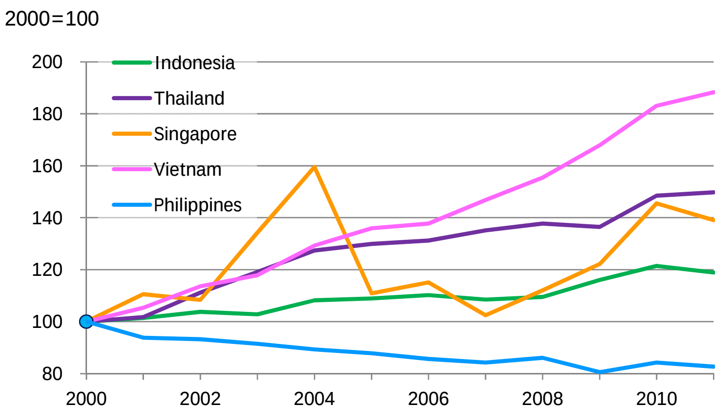
38% of the total primary energy demand, followed by Thailand (21%), Malaysia (13%), and Vietnam (10%). The energy consumption of Vietnam has increased since 2000 by more than 7% per annum, and is expected to exceed that of Malaysia sooner or later.



Source: IEA, "Energy Balances of non-OECD countries 2013"

Figure 2.4.2 Primary Energy Consumption of ASEAN Countries

Regarding energy consumption by energy sources, oil in the past has been widely used not only as transportation fuel, but also power generation fuel, cooking fuel, and so on. Continuing the tradition, oil still today accounts for 36% of the total energy consumption. However, the Southeast Asian region is not endowed with abundant oil resources, and Indonesia, the largest oil producer in ASEAN, became a net oil importer in 2004. In view of the above situation and an increase in power demand, consumption of natural gas and coal has increased in recent years, where they account for 22% and 15% of the primary energy supply, respectively. It is expected that this tendency will continue in the future.



Per Capita TPES in 2011
(ton oil equivalent)

Philippines	0.426
Indonesia	0.863
Thailand	1.714
Singapore	6.452
Vietnam	0.697

Source: ADB, IEA

Figure 2.4.3 Trends in Per-capita Energy Consumption in Selected ASEAN Countries

Along with the robust economic growth, industrialization, and improvement of living standard, per capita energy consumption increased steadily in Vietnam and Thailand, while that for the Philippines declined. In the Philippines, the energy consumption in terms of the total primary energy supply (TPES) remained almost unchanged (the energy consumption in 2011 was just 101% of that in 2000), while its population increased by 23% in the same period.

Table 2.4.4 Key Energy Indicators of Selected ASEAN Countries

Indicator	Unit	Philippines	Indonesia	Singapore	Thailand	Vietnam
GDP (Current Price)	Billion USD	**199.6**	708.0	227.4	341.1	106.4
Population	Million	**92.6**	237.6	5.1	67.3	86.9
GDP/Capita	USD/Person	**2,155**	2,979	44,789	5,067	1,224
Total Primary Energy Supply (TPES)	Million TOE	**40.5**	207.8	32.8	117.4	59.2
Energy self-sufficiency (total energy)	%	**57.9**	183.5	1.2	60.1	111.2
Electricity consumption	TWh	**55.3**	148.0	42.2	149.3	86.9
Power generation capacity	GW	**13.3**	32.9	10.6	31.5	17.5
CO2 Emission (energy origin)	Million ton-CO2	**134.6**	410.9	62.9	248.5	130.5
Per capita TPES	TOE/Person	**0.437**	0.875	6.456	1.745	0.681
Energy intensity per GDP	TOE/1,000 USD	**0.203**	0.294	0.144	0.344	0.557
Per capita Electricity Consumption	kWh/person	**597**	623	8,307	2,218	1,000
Electrification rate [2009]	%	**89.7**	64.5	100	99.3	97.6
Electricity Intensity per GDP	kWh/1,000 USD	**277**	209	185	438	817
Per capita CO2 Emissions (energy origin)	Ton-CO2/person	**1.454**	1.729	12.390	3.692	1.501

Source: ADB, IEA, APEC

Per capita energy consumption of Singapore, at 6.46 tons of oil equivalent (toe), was highest among Asian countries except for Brunei, possibly because of its energy intensive industry structure and hot and humid climate; it was even 65% higher than Japan's 3.90 toe. By contrast, that of the Philippines (0.44 toe) was the lowest among Asian countries, and maintained the position it acquired after overtaken by Vietnam in 2007. The similar trend applies to the electricity consumption in these countries.

Except for Singapore, ASEAN countries are endowed with certain amounts of natural resources, and Indonesia and Vietnam are still net energy exporters. Today's reality, however, may be that their resources are not abundant enough to support the ever increasing energy demand. Indonesia became a net oil importing country in 2004 due to increasing demand and stagnant oil production. Vietnam may follow the same pattern unless significant new discoveries are made. Both countries are also exporting coal, but are now considering curbing exports to preserve resources for respective domestic consumption.

Indonesia used to be the world largest LNG exporting country. Faced with growing domestic demand, however, the country has been cutting down on LNG exports in recent years. Thailand, Vietnam and the Philippines are also producing natural gas, but they are not sufficient to accommodate the ever growing domestic demand. Thanks to the Shale Revolution that began in North America in the middle of the previous decade, expectations are that an abundant LNG supply will become available globally in the future. Although at present the LNG prices for the Asian market are tied up with a price formula that renders extremely steep contract prices, once such a pricing formula for the Asian market is revised to bring the prices closer to the world market, LNG may become a favorable option in pursuit of the two requirements, i.e., energy security and environmental sustainability.

Table 2.4.5 Energy Composition of Selected ASEAN Countries (2012)

(million tonnes oil equivalent,%)

	Philippines		Indonesia		Thailand		Singapore		Vietnam		Total	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Oil	13.0	42.9	71.6	44.9	52.4	44.6	66.2	89.5	16.6	32.0	219.8	50.7
Natural Gas	3.1	10.2	32.2	20.2	46.1	39.2	7.5	10.1	8.5	16.3	97.4	22.5
Coal	9.4	31.1	50.4	31.6	16.0	13.6	0.0	0.0	14.9	28.7	90.7	20.9
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	2.5	8.1	2.9	1.8	2.0	1.7	0.0	0.0	11.9	23.0	19.3	4.4
Renewables	2.3	7.8	2.2	1.4	1.2	1.0	0.3	0.4	0.0	0.1	6.0	1.4
Total	30.2	100.0	159.4	100.0	117.6	100.0	74.0	100.0	52.0	100.0	433.2	100.0

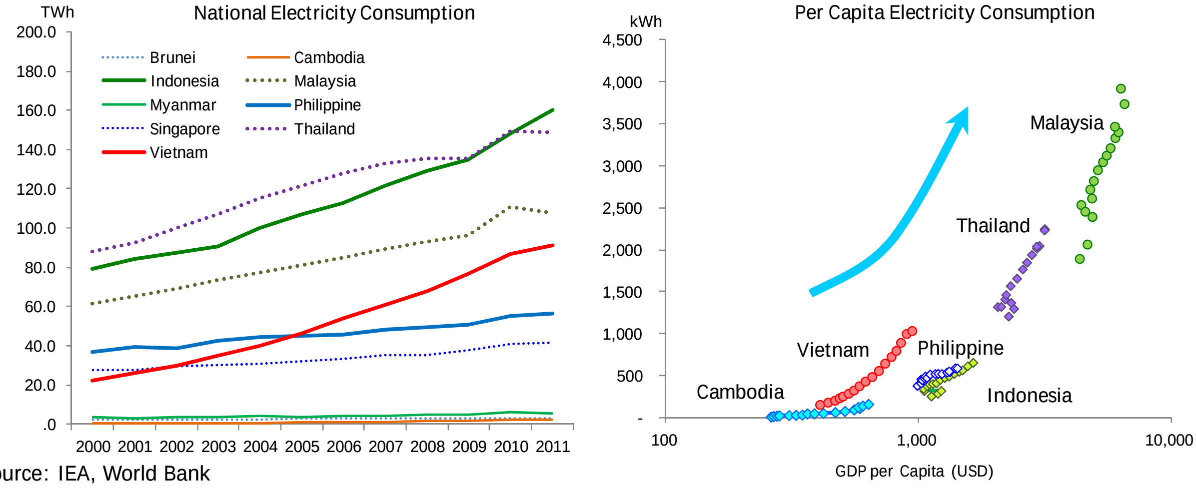
Source: BP Statistical Review of World Energy 2013

Among energy sources in ASEAN countries, oil has the largest share, followed by natural gas and coal, while nuclear energy is yet to be introduced. The Fukushima Dai-ichi nuclear accident of 2011 in Japan has substantially slowed down the nuclear programs in ASEAN countries, and even pro-nuclear governments have grown extremely cautious in developing this socially as well as politically sensitive source of energy. It would be necessary to carefully monitor the future developments in this respect. Hydropower plays a significant role in Vietnam and the Philippines. Geothermal is already an important energy source in the Philippines and Indonesia, and it is likely that additional development projects will continue in earnest. Renewable energies such as solar, wind and micro-hydropower generation are still in a developmental stage except for applications in rural electrification.

2.4.3 Electric Power Demand

Electricity consumption of ASEAN countries recorded a substantial leap during the decade up to 2011. According to the IEA statistics, consumption in the ASEAN region in 2011 was 616 TWh, and the growth rate from 2000 to 2011 registered 6.1%, exceeding the growth of GDP and resulting in the GDP elasticity of 1.2.

Electricity consumption of the Philippines, Indonesia, Thailand, Singapore and Vietnam combined increased 95% or by an annual average of 6.3% during the same period. Except for Singapore, which is already in a matured economic stage and remained at an annual growth of 3.3%, electricity demand increase of the Philippines, at 4.2% p.a., was the lowest among ASEAN countries. Vietnam recorded an exceptionally high rate of 13.7%.



Source: IEA, World Bank

Figure 2.4.4 Electricity Consumption in ASEAN Countries

The average per-capita electricity consumption in ASEAN in 2011 was 1,036 kWh. As shown in Figure 2.4.4, the electricity consumption in Malaysia and Thailand rapidly increased in the latter half of their economic development stage. By comparison, other ASEAN countries are yet to enter a period in which power demand rapidly increases. Since the per-capita electricity consumption of Japan and Singapore in 2010 was 8,394 kWh and 8,307 kWh, respectively, it is considered that a considerable increase in power demand need to occur until power demand enters its maturity in most of the ASEAN countries.

Table 2.4.6 Electricity Consumption of Each Country and Sector in 2011

Country	Industrial		Commercial		Residential		Others		Total	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
Brunei	226	7.4	1,636	53.4	1,202	39.2	-	-	3,064	0.5
Cambodia	430	18.1	657	27.7	1,197	50.5	86	3.6	2,370	0.4
Indonesia	55,375	34.6	38,608	24.2	65,884	41.2	-	-	159,867	26.0
Malaysia	47,218	43.9	36,821	34.3	22,911	21.3	511	0.5	107,461	17.4
Myanmar	2,010	35.2	1,142	20.0	2,564	44.9	-	-	5,716	0.9
Philippine	19,334	34.5	16,624	29.6	18,694	33.3	1,447	2.6	56,099	9.1
Singapore	16,775	40.2	15,653	37.5	6,860	16.4	2,437	5.8	41,725	6.8
Thailand	63,418	42.6	51,019	34.3	32,920	22.1	1,343	0.9	148,700	24.1
Vietnam	48,135	52.9	8,438	9.3	33,349	36.7	1,000	1.1	90,922	14.8
ASEAN	252,921	41.1	170,598	27.7	185,581	30.1	6,824	1.1	615,924	100.0

Source: IEA statistics

Regarding the 2011electricity consumption by sector, the consumption of the industrial sector for the entire ASEAN region was 253 TWh, which accounted for 41% of the total electricity consumption. The electricity consumption of the service sector was 176 TWh (27%), and the consumption of the residential sector was 186 TWh (30.1%). In Singapore, Malaysia, and Thailand which are the leading economies within the region, the ratio of residential electricity consumption to the total consumption has decreased to about 20% or less, while that same ratio is still much higher in other countries. It is expected that the electricity consumption of the industrial sector and the commercial sector will significantly increase in these countries along with economic development.

In its ultra-long-term economic outlook, the IEEJ (previously cited) predicts that the power demand of the ASEAN countries will increase by about 4.5% per annum, and the total power generation will increase from 694 TWh in 2011 to 1,071 TWh in 2020, 1,668 TWh in 2030, and 2,448 TWh in 2040. It is expected that power demand will significantly increase in a region in which electrification will progress in the future (e.g., Indonesia, Thailand, and Vietnam). The IEEJ predicts that the power demand of the ASEAN countries will exceed the current power generation (1,043 TWh) of Japan by about 2020, and exceed the current total power generation (1,563 TWh) of Japan and Korea combined by about 2030, pushing ASEAN up to a position of a major electricity consumer in the world.

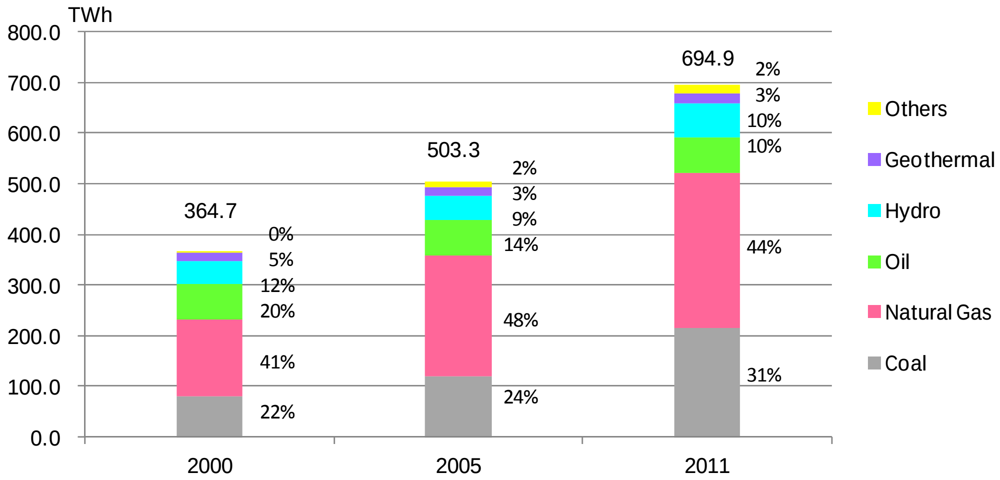
Table 2.4.7 Predicted Final Power Consumption by Country (2011)

	Actual	Estimation (TWh)			Increment(TWh)			Annual Growth Rate (%)			
	2011	2020	2030	2040	11=>20	20=>30	30=>40	20/11	30/20	40/30	40/11
Indonesia	160	275	445	708	115	170	263	6.2	4.9	4.8	5.3
Malaysia	107	166	252	341	59	86	89	5.0	4.3	3.1	4.1
Myanmar	6	20	42	65	14	22	23	14.3	7.7	4.5	8.6
Philippine	56	80	115	158	24	35	43	4.0	3.7	3.2	3.6
Singapore	42	51	63	73	9	12	10	2.2	2.1	1.5	1.9
Thailand	149	218	327	465	69	109	138	4.3	4.1	3.6	4.0
Vietnam	91	148	259	404	57	111	145	5.6	5.8	4.5	5.3
Rest of ASEAN	3	4	6	6	1	2	0	3.2	4.1	0.0	2.4
ASEAN	614	962	1,509	2,220	348	547	711	5.1	4.6	3.9	4.5

Source: IEEJ, "Asia/World Energy Outlook"

2.4.4 Electric Power Supply

The power generation in the ASEAN region in 2011 was 695 TWh, which is about 1.9 times that in 2000(370 TWh). The average growth rate during the above period was 5.9%, which is slightly lower than the growth in electricity consumption at 6.1%. It may be a result of the development of power sources falling behind the increase in power demand, in addition to an improvement in the use efficiency. Natural gas-fired thermal power generation (at 306 TWh) accounted for 44% of the total power generation, and likewise, coal-fired thermal power generation (215 TWh) for 30.9%, while oil-fired thermal power generation (71 TWh) for 10.2%, hydro-power generation (68 TWh) for 9.7%, geothermal power generation (19 TWh) for 2.8%, and other power generation (e.g., biomass, wind power, and solar) (16 TWh) for 2.3%. Natural gas-fired and coal-fired thermal power generation covered 88% of the increase in power generation since 2000, and oil-fired thermal power generation remained on almost the same level. Reflecting the increased utilization of domestic natural gas in respective countries, the share of natural gas-fired thermal power increased until about 2005. However, the growth of coal-fired thermal power has been greater thereafter. Although this reflects the fact that coal-fired thermal power has advantages in terms of supply in the ASEAN region, fuel price, etc., an increase in environmental impact (e.g., an increase in GHG, SOx, NOx, and particle matter emissions) must be taken into consideration.



Source: IEA statistics

Figure 2.4.5 Power Generation on Energy Source Basis

As discussed above, fossil fuels take a dominant position as energy sources for power generation in ASEAN countries today. In particular, Thailand and Singapore are already heavily dependent on natural gas and thus are worried about the high concentration of gas-fired power generation from the viewpoint of supply security and price vulnerability.

Table 2.4.8 Energy Source Composition in Selected ASEAN Countries

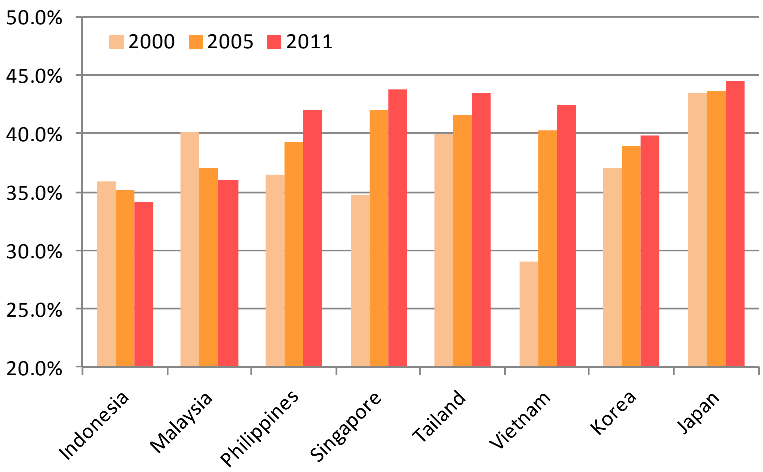
	Philippines		Indonesia		Thailand		Singapore		Vietnam		Total	
	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%	Mtoe	%
Oil	1.48	7.8	8.49	15.9	0.26	0.8	2.22	24.9	1.16	7.2	13.6	10.5
Natural Gas	2.75	14.5	8.64	16.1	22.66	69.5	6.27	70.5	7.63	47.7	48.0	36.9
Coal	5.51	29.1	18.73	35.0	6.92	21.2	0.00	0.0	4.84	30.2	36.0	27.7
Nuclear	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.0	0.0
Hydro	0.67	3.5	1.52	2.8	0.48	1.5	0.00	0.0	2.37	14.8	5.0	3.9
Geothermal	8.54	45.0	16.09	30.1	0.00	0.0	0.00	0.0	0.00	0.0	24.6	18.9
Renewables	0.01	0.1	0.04	0.1	2.30	7.1	0.40	4.5	0.02	0.1	2.8	2.1
Total	18.96	100.0	53.51	100.0	32.63	100.0	8.89	100.0	16.01	100.0	130.0	100.0

Source: IEA, "Energy Balances of Non-OECD countries 2012"

However, the role of natural gas may be appreciated in other countries, due to its cleanness and abundant availability in the international market. Geothermal as energy inputs for power generation is highly valued in the Philippines and Indonesia. We should note, however, that this is due to the IEA calculation formula that assumes the thermal efficiency of geothermal power generation at merely 10%, thereby artificially pushing up the apparent energy independence as a politically favored phenomenon. If we look at the electricity output, the share of geothermal is about 1/2 to 1/3 of those calculated for inputs. Development of other renewable energy sources for power generation is still marginal as yet.

Efficiency of thermal power generation in these countries has been improving fast reflecting construction of new and advanced power plants. Singapore has achieved world class generating efficiency by extensively adopting combined cycle gas turbine (CCGT) plants. In other countries, adoption of advanced coal- and gas-fired plants to accommodate increasing demand as well as replacing obsolete oil-fired plants has contributed to their remarkable efficiency improvement.

However, a decrease in thermal efficiency is observed for countries such as Malaysia that extensively introduced coal-fired thermal power plants in the 2000's and thereafter. A very high thermal efficiency is obtained in the Philippines and Vietnam where gas-fired thermal power plants are operated as the base-load. It is necessary to take note that coal-fired thermal power, although low in fuel cost, increases GHG emissions as compared with gas-fired thermal from the point of thermal efficiency.



Efficiencies by Fuel type (2011)

	Coal	Oil	Gas	Total
	%	%	%	%
Indonesia	31.8	35.2	38.7	34.1
Malaysia	35.0	38.9	36.5	36.0
Philippines	35.2	36.7	56.7	42.0
Singapore	-	38.3	45.2	43.7
Thailand	34.2	40.3	47.8	43.5
Vietnam	35.0	32.3	49.1	42.4
Korea	34.7	32.9	49.7	38.4
Japan	41.4	44.4	47.4	44.6

Source: IEA Energy Balances of OECD/Non-OECD Countries 2013

Figure 2.4.6 Thermal Power Generation Efficiency in ASEAN Countries

It is considered desirable to promote integration and interconnection of regional grids in the ASEAN countries in order to pursue their policies such as further improvements in thermal efficiency by increasing the size of power plants, strengthening supply security, suppressing emissions of environmental pollutants, and promoting energy conservation through the use of smart grid technology. It is desirable to implement the future power market design taking account of the achievements of such economic benefits.

Table 2.4.9 Predicted Power Generation in ASEAN Countries

	Actual	Estimation (TWh)			Increment(TWh)			Annual Growth Rate %			
	2011	2020	2030	2040	11=>20	20=>30	30=>40	20/11	30/20	40/30	40/11
Indonesia	182	310	498	788	128	188	290	6.1	4.9	4.7	5.2
Malaysia	130	201	298	387	71	97	89	5.0	4.0	2.6	3.8
Myanmar	7	23	50	78	16	27	28	14.1	8.1	4.5	8.7
Philippine	69	95	137	188	26	42	51	3.6	3.7	3.2	3.5
Singapore	46	57	70	81	11	13	11	2.4	2.1	1.5	2.0
Thailand	156	217	324	476	61	107	152	3.7	4.1	3.9	3.9
Vietnam	99	163	285	444	64	122	159	5.7	5.7	4.5	5.3
Rest of ASEAN	5	5	6	6	0	1	0	0.0	1.8	0.0	0.6
ASEAN	694	1071	1,668	2,448	377	597	780	4.9	4.5	3.9	4.4

Source: IEEJ, "Asia/World Energy Outlook"

In the ASEAN countries, it is expected that power sources will be developed in anticipation of a steady increase in power demand. The IEEJ predicts that natural gas and coal will mainly be involved in the development of power sources. While the approaches toward nuclear power generation may differ among the ASEAN countries, it is not likely that large-scale nuclear power generation is implemented by 2040. Although geothermal energy, hydro-energy, and other renewable energies will be developed earnestly, the extent of their expansion will remain up to about 9% of the increase in the total power generation capacity.

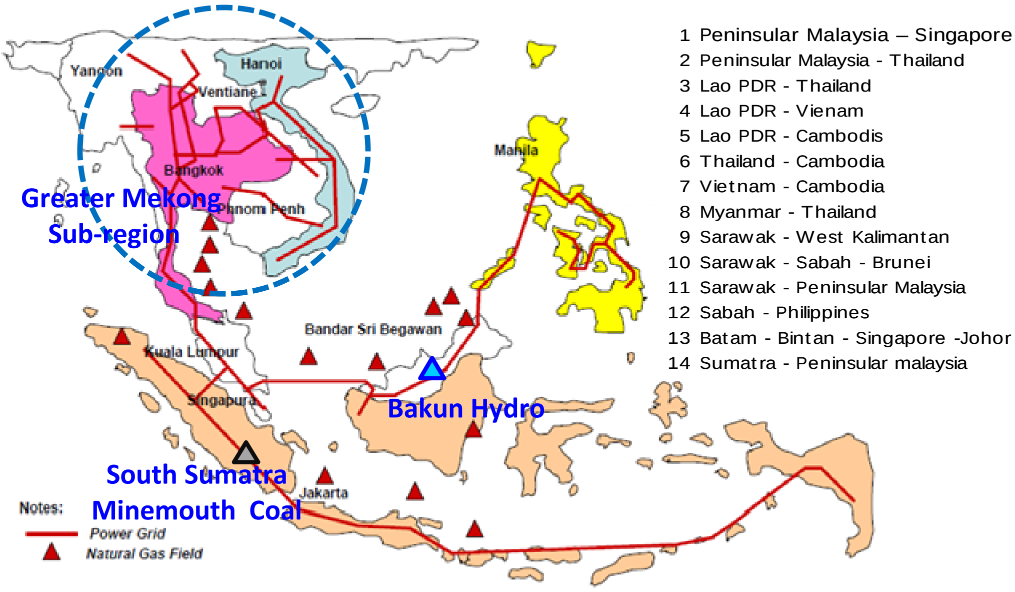
Table 2.4.10 Power Generation and Composition on Energy Source Basis

	Actual	Generation (TWh)			Compisition (%)			Increment (TWh)			
	2011	2020	2030	2040	2020	2030	2040	11=>20	20=>30	30=>40	Total
Coal	216	357	595	951	33	36	39	141	238	356	735
Oil	71	70	71	72	7	4	3	-1	1	1	1
Natural gas	307	497	752	1067	46	45	44	190	255	315	760
Nuclear			45	104	0	3	4	0	45	59	104
Hydro	73	94	118	129	9	7	5	21	24	11	56
Geothermal	19	38	59	80	4	4	3	19	21	21	61
Others	8	16	29	46	1	2	2	8.1	13	17	38.1
ASEAN	694	1071	1668	2448	100	100	100	377	597	780	1754

Source: IEEJ, "Asia/World Energy Outlook 2013"

2.4.5 International Grid Interconnection

In 1986, the Agreement on ASEAN Energy Cooperation was signed by the ASEAN countries in Manila, and the ASEAN Vision 2020 adopted in Malaysia in 1997 agreed on promotion of international grid interconnection through the ASEAN Power Grid program. Fourteen grid connection projects have been studied under the Heads of ASEAN Power Utilities/Authorities (HAPUA), and some of the regional links have already been implemented. A wide-area interconnection project that utilizes the hydropower resources in the Mekong River Basin has been in progress. However, the ASEAN Power Grid program is a grand program, and the construction plans for the key interconnection lines have not yet been implemented.



Source: Prepared based on Puguh Sugiharto Indonesian Electrical Power Society (MKI)

Figure 2.4.7 Plan for Future ASEAN Grid Interconnection

Elsewhere, electricity has been exported to Vietnam by utilizing the hydropower resources in Yunnan province in China (upstream of the Red River), with a project for future expansion in plan. A project that will export power generated by hydropower generation in Myanmar to China has been under development.

A wide-area development plan involving Laos, Cambodia, Vietnam, Thailand, Myanmar, and the southern part of China has been developed under the Greater Mekong Subregion Economic Cooperation Program[25], and projects for effective utilization of hydropower resources (e.g., Mekong River), or interconnection of the grids of respective countries have been gradually implemented. According to material published by the Asian Development Bank (ADB), international electricity trading in Southeast Asian countries including countries situated around the Mekong River and China reached 34,139 GWh in 2010. The Greater Mekong Subregion development program includes projects that aim to construct several large-scale hydroelectric dams in Laos and Myanmar. While there is a need to address the environmental issues accompanying the large-scale development, it is expected that the western corridor of the ASEAN Power Grid program will be progressively formed along with the development of power sources in the Mekong River Basin.

[25] ADB, "Greater Mekong Subregion Power Trade and Interconnection - 2 Decades of Cooperation", September 2012

Table 2.4.11 Electricity Trading and Net Import in Mekong River Basin in 2010

	Import	Export	Total Trade	Net Import
	GWh	GWh	GWh	GWh
Cambodia	1,546	-	1,546	1,546
Laos	1,265	6,944	8,210	-5,679
Myanmar	-	1,720	1,720	-1,720
Thailand	6,938	1,427	8,366	5,511
Vietnam	5,599	1,318	6,917	4,281
China	1,720	5,659	7,379	-3,939
Total	17,069	17,069	34,139	-

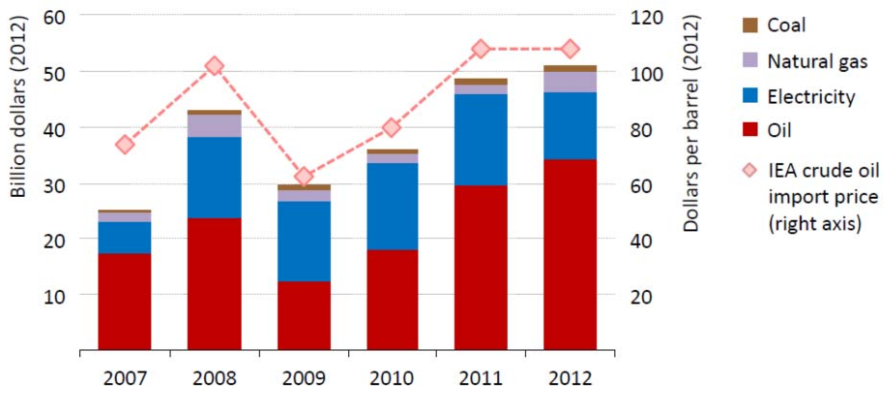
Note: The values listed in this Table include only those of the Greater Mekong Subregion, and exclude those on electricity trading between Yunnan/Guangxi and other regions of China, as well as Thai's imports from Malaysia.
Source: ADB, "Greater Mekong Subregion Power Trade and Interconnection: 2 Decades of Cooperation」Sep.2012"

The core of the eastern corridor is the Bakun hydropower development in Sarawak, Malaysia, as described above in connection with Indonesia. It is not technically very difficult to implement a link from Sarawak grid to West Kalimantan grid (Indonesia). In contrast, a link to Peninsular Malaysia or Indonesia is a large-scale project that requires construction of long-distance and large-capacity submarine cables. However, since large-scale Bakun hydropower development has progressed considerably, it is expected that the eastern corridor will be gradually developed in the future.

A program that aims to transmit power generated by mine-mouth power plants that utilize brown coal from southern Sumatra to Java has become more realistic. The above program will establish interconnection between Sumatra and the Malay Peninsula, along with the links between Java, Sumatra, and the Malay Peninsula. The ASEAN encompassing from Indonesia to Myanmar is a vast region having an east-to-west dimension of more than 5,000 km and a north-to-south dimension of more than 4,000 km. If a wide-area grid interconnection that links up such a vast area is materialized, it will make it possible to implement improvements in thermal efficiency through large-scale power generation, and effective power utilization that comprehensively takes advantages of the differences in time, climate, business or lifestyle patterns, and the like.

2.5 Energy Subsidies in ASEAN Countries

Energy subsidies have been practiced traditionally among resource rich ASEAN countries, namely, Indonesia, Malaysia, Thailand, Vietnam, Brunei and Myanmar. While energy supply was so plentiful that a substantial part of production was directed to export, people took it for granted to use locally available energies at cheap prices and politicians provided subsidies to make energy affordable for everybody. Since energy prices, in particular oil prices, jumped up in the middle of the last decade while concerns on global warming were growing simultaneously, energy subsidies have become a controversial subject worldwide. Nevertheless, energy subsidies in the ASEAN region have been increasing in recent years according to the IEA as shown in Figure 2.5.1.



Source: IEA "Southeast Asia Energy Outlook," September 2013.

Figure 2.5.1 Fossil Fuel Subsidies in ASEAN

Energy subsidies lower the price paid by consumers to below international market levels, or in the case of electricity generated from fossil fuels, to below the level of full cost of supply. Keeping final prices low, energy subsidies encourage wasteful use of energy and discourage investment for energy efficient but expensive appliances and technology.

Box: Energy Subsidies

Energy subsidies may be divided into two categories, namely production subsidies and consumption subsidies, according to the direct beneficiary of subsidies. In addition to direct financial transfer such as grants to producers or consumers, there are various types of subsidies such as trade instruments (ex. Quotas, tariffs), regulations(ex. price control, resource access), tax breaks, credit(ex. low interest loan, back guarantee), risk transfer (ex. insurance) and energy related services provided by governments at less than full cost.

Table 2.5.1 Fuel Subsidies in Major ASEAN Countries (2011)

	Vietnam	Indonesia	Philippines	Malaysia	Thailand	Brunei
Average subsidization rate	15.5%	23.2%	4.3%	18.4%	20.0%	36.5%
Subsidy ($/person)	46.7	90.7	15.3	253.3	150.0	1158.6
Share of GDP	3.4%	2.5%	0.7%	2.6%	3.0%	3.0%
Subsidy by fuel (billion US$)						
Oil	1.02	15.72	1.46	5.35	3.29	0.31
Natural Gas	0.16	0.00	0.00	0.89	0.48	0.00
Coal	0.02	0.00	0.00	0.00	0.85	0.00
Electricity	2.92	5.56	0.00	0.94	5.67	0.16
Total	4.12	21.28	1.46	7.18	10.29	0.47

Source: IEA online database "Fossil-fuel consumption subsidy rates as a proportion of the full cost of supply, 2011
http://www.iea.org/subsidy/index.html Information on other ASEAN countries were indecisive.

Fossil fuel subsidies in Southeast Asia amounted to $51 billion in 2012; in which oil constituted 68% or $34 billion, followed by electricity at 24%, or $12 billion.[26] Spending is significant naturally in net oil exporters, namely Indonesia and Malaysia, but in a net oil importer, Thailand, as well. These countries explain that subsidies are used to avoid social instability and also to maintain international competitive edge of the domestic industries. In contrast, the Philippines has kept negative political posture against energy subsidies, while its electricity tariff is ranked in the highest group in Asia.

Under the circumstance, ASEAN countries are implementing reform of fossil fuel subsidies as summarized in Table 2.5.2. We will look into the current status of VIP countries as below.

Table 2.5.2 Fossil-fuel Subsidies and Reform Efforts in ASEAN

Country	Products Subsidized	Reform Efforts
Brunei	Diesel, Gasoline, LPG, Electricity	Increased diesel and gasoline prices in 2008 for foreign-registered vehicles to limit "fuel tourism" from Malaysia, and applied a second increase for foreign vehicles in 2012
Indonesia	88-octane gasoline, Diesel, Kerosene for households and small businesses, LPG, Electrcity	Increased price of gasoline by 44% and diesel by 22% in June 2013. Promoting natural gas use in transport to reduce oil subsidies. Continuing successful Kerosene-to-LPG conversion programme, which started in 2007. Electricity tariffs are set to rise by 15% in 2013 (based on quarterly increases) for all but consumers with the lowest level of consumption.
Malaysia	95-octane gasoline, Diesel, LPG, Electricity	In September 2013, subsidies to gasoline and diesel were reduced in a bid to cut the budget deficit. Plans to implement on 2014 a subsidy removal programme set out in 2011 to gradually increase natural gas and electricity prices.
Myanmar	Electricity, Natural Gas, Kerosene	As part of power sector reforms, electricity prices were increased in January 2012. Diesel and gasoline prices were indexed to Singapore spot market prices in 2011.
Thailand	LPG prices controlled. Diesel and Natural Gas (for vehecles) controlled to minimize effect of volatility in international prices. Electricity for poor households.	From September 2013, increasing LPG prices every month for all but street venders and consumers with the lowest level of electricity consumption. Increased electricity tariffs in September 2013, which will be revised every four months.
Vietnam	Diesel, Gasoline, Natural Gas, Electricity	Gradually moving towards market prices for oil and natural gas. Plans to introduce a roadmap for the phase-out of fossil-fuel subsidies.

Source: IEA "Southeast Asia Energy Outlook," September 2013.

[26] IEA "Southeast Asia Energy Outlook," September 2013

2.5.1 Vietnam

Vietnam does not spend energy subsidies directly out of its national budget, however, as a matter of fact, it spends a considerable amount indirectly through price regulations and tax policies, as well as in a form accumulating deficits at state-owned enterprises.

Unlike Indonesia and the Philippines, most of energy firms in Vietnam are state-owned. The government provides them with subsidies in the form of tax breaks and refunds. It also sets lower energy prices below the world market prices and enforces energy supply to domestic industries at cheaper prices. For example, the price of coal for power generation is set below the international market price, so that generating companies can use cheaper coal in power production. Likewise, petroleum products are priced lower than the international prices. [27] Electricity tariff is also regulated lower than cost. IEA estimates that the amount of indirect energy subsidies in Vietnam amounted to US$4.12 billion, or US$47 per person in 2011, 70% of which were spent for electricity.

Petroleum products prices are regulated to keep the retail prices at an affordable level, but losses are incurred at state-owned companies. Petroleum supply business unit of state owned Petrolimex (with market share of refined oil products at around 60%) recorded a loss of 219 billion VND in 2010 and 1.8 trillion VND up to June 2011. In February 2012, Ministry of Finance reduced petroleum and jet fuel import taxes to between 3 percent and zero percent and on kerosene and diesel from 5 percent to 3 percent, in response to rising global market prices. Traders were forced to take additional losses, as prices at the pump were between VND1,300 and VND2,400 per litre lower than import prices for different products; roughly up to 12% of the price per litre of petrol and other products.

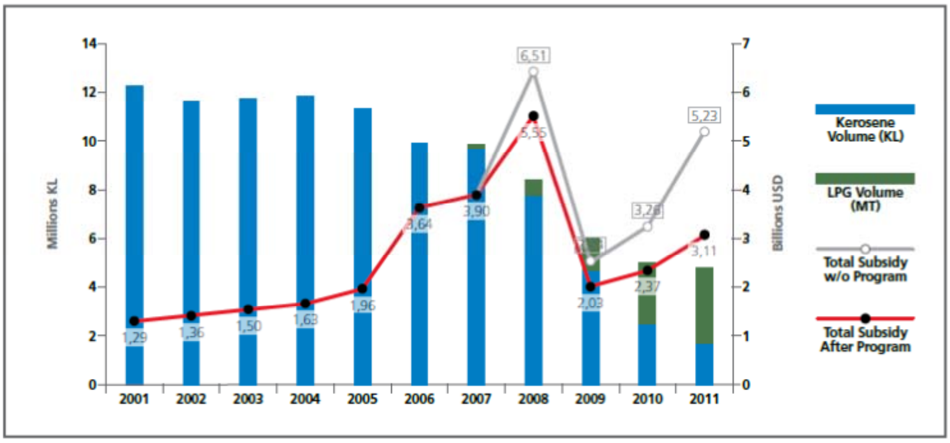
While marketers enjoy preferential access to financial resources and some measure of protection from competition, supply side subsidies in the refined petroleum sector are limited. Most subsidies are concentrated on the demand side, and as with the electricity sector are largely composed of the losses of state owned enterprises, which are eventually borne by the Government. Preferential loans cover some of the losses, preferential tax treatment as well as Government investment in energy infrastructure and R&D.[28]

[27] Base prices of petroleum products for wholesale by each importer and refiner are regulated and reviewed monthly to be the sum of a) FOB + freight cost +insurance, b) import tax, c) special consumption tax (10% for gasoline only), d) regulated domestic refining and/or distribution and other cost, e) regulated profit margin, f) contribution to oil price valorization fund, and VAT. As a mechanism, there is no apparent subsidy from the government. However, regulation on the cost and profit margin has often incurred lagged and insufficient adjustment, causing implicit fuel subsidies for consumers.

[28] UNDP “Fossil fuel Fiscal Policies and Greenhouse Gas Emissions in Viet Nam,” May 2012.

2.5.2 Indonesia

Indonesia has been providing a huge amount of subsidies traditionally. As a result, the fossil fuel subsidy amounted to 21.6% of the state budget in 2012 which jumped to 27.5% in 2013 as shown in Table 2.5.3. In particular, subsidies for petroleum products such as gasoline, kerosene and LPG as cooking fuel are huge and still increasing substantially. During the last decade, Indonesia has been trying to reduce fossil-fuel subsidies by various means. Indonesia designed the Unconditional Cash Transfer program (UCT) with the fuel price increases in 2005.[29] Then the country implemented a kerosene-to-LPG conversion programme in 2007[30] in conjunction with the UN Millennium Development Goals campaign and successfully reduced the subsidy for kerosene. Pertamina, the state-owned oil company reports that the program has significantly reduced subsidies for cooking fuel while improving energy efficiency significantly as shown in Figure 2.5.2. However, LPG is also subsidized, though to a lesser degree than kerosene.



Source: Pertamina "Kerosene to LP Gas Conversion Programme in Indonesia," 2011

Figure 2.5.2 Subsidized Volume and its Subsidy on Kerosene and LPG

Table 2.5.3 Fossil-fuel Subsidies in Indonesia

	2011	2012	2013
	trillion Rupiahs	trillion Rupiahs	trillion Rupiahs
Central Governement Expenditure	836.6	965.0	1154.4
Fuel Subsidies	187.6	208.9	317.2
Oil Subsidy	136.6	168.6	274.7
Non-oil Subsidy	51.0	40.3	42.5
Ratio to the Government Expenditure	%	%	%
Fuel Subsidies	22.4	21.6	27.5
Oil Subsidy	16.3	17.5	23.8
Non-oil Subsidy	6.1	4.2	3.7

Source: Statistics Indonesia "Statistical Yearbook of Indonesia 2013"

[29] UCT for the poor (19.2 million poor and near-poor households) was piloted to compensate for increased fuel prices. The government is currently committed to begin testing different approaches for identifying the most effective model of conditional cash transfers appropriate for Indonesia. UNDP http://www.ipc-undp.org/PageNewSiteb.do?id=121&active=3#indonesia (read January 2014)

[30] It aims to enable 85% of households to use LPG or natural gas for cooking by 2015.

In 2010, Indonesia announced plans to eliminate energy subsidies by 2014. The gap between international and domestic prices was to be progressively reduced, in an effort to moderate the impact on the poor. According to Indonesia's 2011 state budget, 11% of government expenditure in 2011 was earmarked to energy-consumption subsidies, compared with 13% in 2010 and 19% in 2008. However, this plan was revised back and got worse in the 2013 state budget as shown in Table 2.5.3.

As a typical indirect subsidy, it is defined in the standard contact for development of energy resources that the DMO (Domestic Market Obligation) portion of the production must be delivered to the domestic market at 25% of export price; i.e., at a 75% discount from international market price. In the case of oil and gas, the DMO portion of production constitutes the feedstock mix of the state oil company Pertamina together with imported crude oil and petroleum products, and is thought to be the source of the fund for implicit fuel subsidization. Prices of products for the lower income group are regulated by the government accordingly; they are regular grade gasoline (its brand name is "Premium" with octane number of 89 while higher grades are named Pertamax (RON 92) and Pertamax Plus (RON 95)), regular grade diesel (brand name is "Solar" with cetane number at 48), kerosene, and LPG in 3kg canisters. In order to reduce subsidies on petroleum products, the Indonesian government raised prices of Premium and Solar diesel by 44% and 24%, respectively, in June 2012.[31] [32]

In case of coal, some 80% of the domestic consumption supplied locally goes to power generation and the remaining 20% to steel and cement industries. Coal is supplied to these industries at a discounted price through the DMO mechanism, which aims at securing continued domestic coal supply and optimization of state revenue. Under the DMO policy for coal, coal mining companies as well as coal consuming industries must register with the government authority the production and consumption plan for the next year. Then, the government determines the Minimum Domestic Coal Supply Obligation Percentage (PMPBDN) for each company and the

[31] Most modern cars run on RON 92 or higher octane fuel, but subsidies for Premium are encouraging Indonesian motorists to use lower-grade fuels which, in addition to creating higher pollutants, can damage vehicle engines, particularly more modern engines. On January 30, 2012, the government announced a plan to reduce the subsidy on Premium, effective April 2012.The reform plan includes two components: i) prohibiting consumption of Premium by private 4-wheel vehicles in Greater Jakarta and official vehicles in the Java and Bali regions, and ii) the deployment of alternative, gas-based transport fuels: Compressed Natural Gas (CNG) and Liquid Gas for Vehicles (LGV),4 with a target of converting 46,000 vehicles to CNG and 250,000 vehicles to LGV in the Java-Bali area by the end of 2012. The government aims to develop new infrastructure to support both components, including 55 CNG and 108 LGV filling stations in the Java-Bali area in 2012. *GSI and IISD "Indonesia's Fuel Subsidy", March 2012.*

[32] Indonesia's government has cut a huge fuel subsidy after months of political haggling, causing petrol prices to rise by 44% and diesel by 22%. Thousands of motorists rushed to fill up before midnight, after the measure was announced late on Friday (June 20, 2012). The announcement sparked clashes in the capital, Jakarta, where protesters blocked roads and fought with police. Indonesians had been demonstrating on the streets of many major cities all week in anticipation of the rise. The measure was agreed by parliament on Monday, but MPs did not say when the new prices would come into effect. *http://www.bbc.co.uk/news/world-asia-23015511* Price of Premium was raised from 4,500 Rupiahs per litre to 6,500 Rupiahs while Pertamax and Pertamax Plus are priced 8,350 Rupiahs and 8,750 Rupiahs, respectively. Price of Solar diesel was raised from 4,500 Rupiahs to 5,500 Rupiahs.

Indonesian Coal Price Reference (ICPR), average monthly coal prices. The ICPR is used as reference price for domestic transactions. Mining companies are allowed to export their products after fulfilling their domestic market coal obligation. Mining companies are also obligated to help support domestic coal supply.

In addition to the subsidy cutting on gasoline and diesel as above, in January 2014, Pertamina announced a 68% hike of the retail price for non-subsidized 12-kg canisters LPG, which is typically consumed by middle and high-income households and industries. However, President Yudoyono immediately cut in and requested to review this hike saying "the government has to take into account the social and economic impact when the public considers the price to be too high." [33] It seems it is yet a long way for Indonesia to be fully relieved from fossil-fuel subsidies.

2.5.3 Philippines

In the Philippines, a substantial amount of fossil-fuel subsidy is paid out of the Oil Price Stabilization fund (OPSF), which was created in 1984 following the experiences of the oil crisis and operated by the DOE. In the original concept, no subsidies would be required from the Government. However, it became increasingly to be used for political purposes in the 1990s, and now amounts to 0.7% of the GDP.[34]

For the power sector, however, the Government of the Philippines keeps the political posture opposing fossil fuel subsidies, although the government occasionally had to subsidize the state owned power sector in the course of implementing power sector reform, or EPIRA. At present, only cross subsidies within the power sector are prevailing, namely the Universal Charge for rural electrification and Lifeline Rates applied for low income households. The Universal Charge is collected on top of the electricity tariff and paid to the Power Sector Assets and Liabilities

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[33] The price of non-subsidized 12-kg canisters was pushed up by Rupiah 3,959/kg ($0.33/kg) from Rupiah 9,809/kg with effect from January 1, 2014, which translates to a price of Rupiah 117,708 for each 12-kg canister, Platt's previously reported. Pertamina sells LPG under two categories -- subsidized and non-subsidized. The non-subsidized LPG is sold in 12-kg canisters at government-capped prices, but Pertamina is not compensated for losses incurred from sales at below international market prices. The non-subsidized LPG is typically consumed by middle and high-income households and industries. Subsidized LPG is sold by the government in 3-kg canisters at Rupiah 4,250/kg, and the price of these canisters was not affected. (Platt's--6Jan2014/1259 am EST/559 GMT)

[34] In simple terms, the Fund operated so that producers could draw from the Fund when landing costs were high, but they would contribute back to the Fund when landing costs were low. In an ideal case, the drawdowns would be equivalent to the contributions and no subsidies would be required from the Government. The Fund was administered by the Department of Energy, although petroleum product prices were set bimonthly by the Energy Regulatory Board. Prices were supposed to be based on landing costs (import price with exchange rate movements) and the Board would hold public hearings prior to each price adjustment. In reality, however, there was much political interference in the pricing policies, particularly during times of high inflation (price adjustments were informally approved by the President) and public hearings were confrontational (e.g., between producers, consumers and the government). As a result, price adjustments were usually too late and too small. The Fund became depleted during times of high oil prices and required PHP17.6 billion (approximately US$650 million) in government subsidies between 1990 and 1997. The subsidies were equivalent to 0.2 per cent of GDP or 0.8 per cent of central government expenditure and had significant impact on public sector deficit. GSI and IISD 's meeting report of the forum "Fossil-Fuel Subsidy Reform" November 2012.

Management (PSALM) or directly collected from privately owned power plants according to their power production quantity. Then, PSALM disburses the fund to rural electrification operators such as electric cooperatives according to their registered record. The cumulative amount of the Universal Charge remittances to PSALM as of 30 April totaled to almost Php 30 billion as shown in Table 2.5.4, of which the total amount received during the period November 2012 through April 2013 was Php 3.7 billion. They are mostly used for missionary electrification purposes, while some amount was disbursed as an environmental charge.

Table 2.5.4 Universal Charge Remittances, Interests and Disbursements as of April 2013

(in billion PHP)

Particulars	Remittances	Interests	Disbursements	Balances
Missionary Electrification	28.439	0.043	28.46	0.022
Environmental Charge	1.224	0.079	0.498	0.805
Stranded Contract Cost	0.185	-	-	0.185
Total:	29.848	0.122	28.958	1.012

Source: Philippine DOE

The Aquino Administration, when it took office in 2010 decided to accelerate rural electrification, and has since injected a substantial amount into the projects from the Malampaya Fund in addition to the Universal Charge.[35] In 2013, this policy was further accelerated with enforcement of the Act Strengthening the National Electrification Administration. There are about 33,000 sitios (rural enclaves far from the village center) in the Philippines. The Department of Energy (DOE) and National Electrification Administration (NEA), have raised their rural electrification goal to 10,394 sitios before the end of 2013 from the original 7,000 under the Sitio Electrification Program (SEP). This will bring the aggregate number of sitios provided with electricity to 18,077. By 2014, the target will be an additional 7,107 sitios and by 2015, another 7,257, thus to complete rural electrification by the end of 2015.

The Lifeline Rate is a subsidized electricity rate given to low-income residential power customers who are not able to pay the full cost of electricity. Customers with an average monthly consumption of 21 to 50 kWh are entitled to a 50% discount, those consuming an average of 51-70 kWh entitled to a 35% discount, and those of 71 to 100 kWh, a 20% discount.

[35] Three out of 10 particular energy projects for which the Malampaya Fund was intensively injected since 2010 were projects for rural electrification, namely, missionary electrification, barangay line enhancement and sitio electrification projects.

Chapter 3 Basic Method of the Study

3.1 Method of Approach

With a view to prepare policy recommendations for ASEAN countries, this study aims to establish a desirable energy supply structure for 2050 by way of analytical simulations using a newly constructed energy supply model. At first, the study was conducted individually for the Philippines, Indonesia and Vietnam. The interim study outcome was presented at the Tokyo Symposium held on December 13, 2013. Discussions at the symposium as well as comments from the Advisory Committee are considered for further improvement of the model and adjustment of cases and assumptions.

On the whole ASEAN region, a macro-level energy supply/demand analysis is run on the whole region, to examine policy options to simultaneously pursue low-carbonization and energy efficiency improvement. Using the same model, it is possible to conduct further analyses on the effect of establishing mutual energy accommodation system among neighboring ASEAN countries, such as international linkage of power transmission lines and gas pipelines as well as power supply system across international border in the Greater Mekong Region. However, it is necessary to collect detail data and adjust complex assumptions to conduct such analysis. Because of time constraints, such simulation was deferred to the next opportunity.

On the three countries selected for case studies, analyses are being made mainly on the following items;

a. What kind of policy sets should be considered in achieving a "well balanced energy mix" while trade-offs are often observed between policies aiming at low-carbonization and those aiming at energy efficiency?
b. What kind of policy sets will be most desirable while the policy selection will become considerably different when designing the energy sector under principles of government-driven or market-driven?
c. In addition, effect of establishing mutual accommodation system with neighboring countries as well as common policies in unison shall be considered in due course.

The above analysis has been further reviewed at the Advisory Committee as well as collaborative discussion among IEEJ, Castalia and JICA. The final outcome were presented to ASEAN countries during workshops held in February 2014.

3.2 Energy demand for 2050

The energy demand outlook is the fundamental assumption as the starting point of this Study. The energy demand outlook for 2050, for the whole ASEAN region as well as individually for the Philippines, Indonesia and Vietnam has been projected based on researches on the preceding studies available as mentioned below. The study team has been looking into these studies mainly on the following points;

a. Assumptions for the forecast, such as future economic growth, technology development, fuel prices, and so on,
b. The base year of the forecast, and
c. Outcome of the forecast

Studies listed for review are; ADB (Outlook 2013 – Asia's Energy Challenge, Building a Sustainable Energy Future – The Greater Mekong Subregion; Asia 2050 Realizing the Asian Century), IEA (World Energy Outlook 2012; 2013; Southeast Asia Energy Outlook-2013), The World Bank (Winds of Change – East Asia's Sustainable Energy Future), JICA (The Study for Supporting Low-carbonization Projects in Indonesia), WEC (Deciding the Future Energy Policy Scenarios to 2050), EU (World Energy Technology Outlook 2050 - WETO H2), (Super Long-run energy strategies of various countries (ex. The Energy Market in Indonesia, Biomass Opportunities in Vietnam, etc.), and IEEJ's own analyses (The 3rd ASEAN Energy Outlook; Asia/world Energy Outlook 2013; APEC Energy Demand and Supply Outlook 5th Edition, and so on).

Based on the above study, major assumptions are set out as explained in Chapter 4.

3.3 Concept of Model

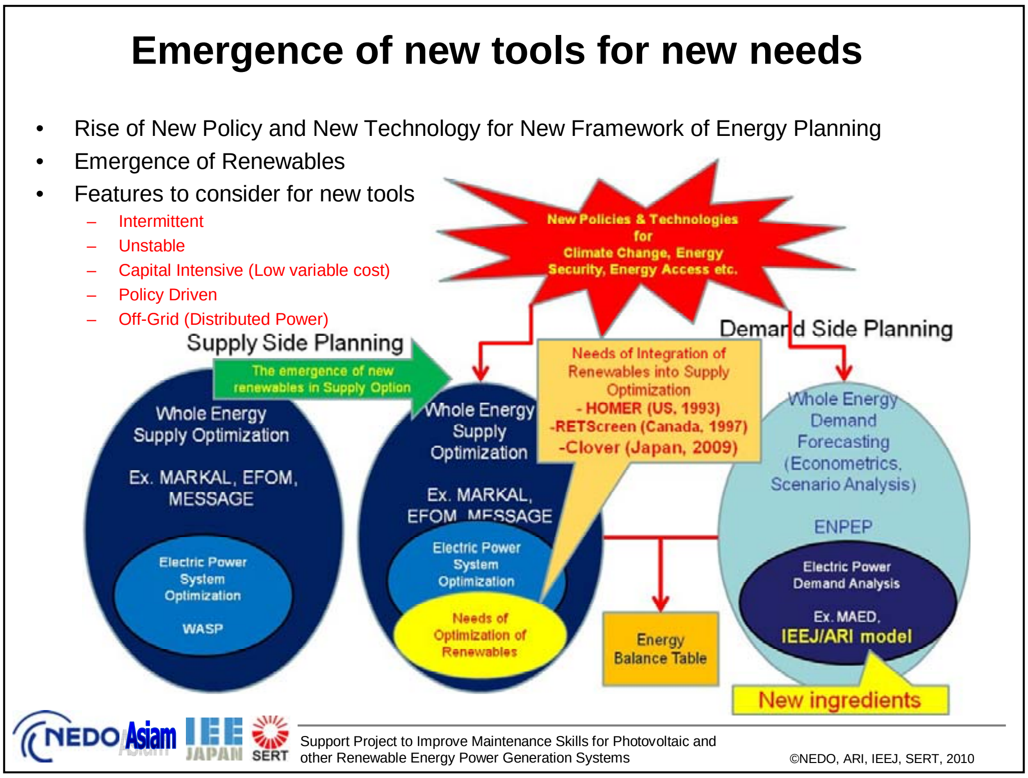
The energy best mix model for power development is the core tool for conduct of analytical simulation scheduled in this Study. The basic concept of the model is developed according to the following approach.

3.3.1 Review of existing models and tools

Energy is the fundamental platform for economic development while the investment on energy related equipment is huge in size with long lead time, and it is very important to guide the energy sector development consistently with national development plan. Therefore, the government sector sets up national future energy plans in many countries. Implementing the planning, in a general approach, energy demand outlook will be projected first, and then energy supply plan will be constructed considering various elements including availability, price, required investment amount, impact on social environment, and other factors relating to each energy source.

The calculation is complicated and an analytical model has to be constructed using proper tools. Optimization planning method is usually applied in these analyses. In particular, the linear programming method is applied for analysis of a system with huge number of variables, and it is the standard tool for model analysis of energy/electricity planning. In recent days, with emergence of renewable energies, optimization tools are increasingly introduced to utilize them effectively as shown in Figure 3.3.1. Among the tools popular in ASEAN and other developing countries are

MARKAL (Market Allocation Model), EFOM (Energy Flow Optimization Model), WASP (Wien Automatic System Planning), and experimental new tools are being introduced in the US and Canada which are able to analyze selection of renewable energies.



Note: The above figure is prepared by IEEJ for explanation of constructing optimum introduction plan of renewable energies for a project run by NEDO.

Figure 3.3.1 Review of Existing Tools Accommodating Renewable Energies

The above tools, however, represent a model to produce an optimal plan only for a period of 10 – 20 years and as extension of the existing infrastructure and technologies. They would not be appropriate for application in this Study, as we are going to analyze an extremely long period up to 2050; the existing infrastructure will be mostly replaced and conditions for technology progress will be totally different for such a super-long period.

3.3.2. Building a New Model

Under the circumstance, we have constructed a new model in this Study. There are several examples of academic studies aiming at assessment of super long term planning as we plan in this Study, such as those conducted by teams of Tokyo University, Keio University, etc. However, since we are given only a limited time for this Study, it is very difficult to develop a realistic model applicable to each objective country considering their specific features. In this regard, we should consider the following points as a realistic solution;

a. Limit the number of variables to be fabricated in the model as small as possible, and define the relationship and logic of them as simple as possible.

b. Apply flexible arrangement on the relationship of variables

Gist of our approach on the method of approach, applicable software and structure of the model is explained below.

Method of Approach and applicable Software

Setting the above two points as the principle for the analytical method, the model should become a complex one but with small number of variables. In such a case, instead of the popular linear programming method, it is desirable to apply a more advanced method called "non-linear programming." It should also be considered that such model and operation technique should be structured to be easy for technical transfer as eventually they are intended for wide utilization among ASEAN countries in future.

In view of the above points, we have adopted an approach to construct the model on the widely used Excel spread sheet software. IEEJ and Asiam Research Institute (ARI), a Japanese research firm, have jointly developed a model construction software "SimpleE" and method of approach based on this concept. IEEJ has used them for over 15 years in the technology transfer seminars under the APEC expert dispatch program. This approach, transferred as above, has been used in the three countries listed for this Study for energy demand forecasting and long term planning.

In order to construct the above mentioned model, it is the principal requisite that non-linear programming model could be developed on an Excel spread sheet. The function of the "Solver" provided in Excel as academic example is quite limited, but unable to accommodate the requirement for developing the above model. Therefore, we plan to use the "SimpleE" model building software, which is mounted with an engine to enhance such function of the Solver. SimpleE can be used as "Add-in" software of Excel, and their relationship is as shown in Figure 3.3.2.

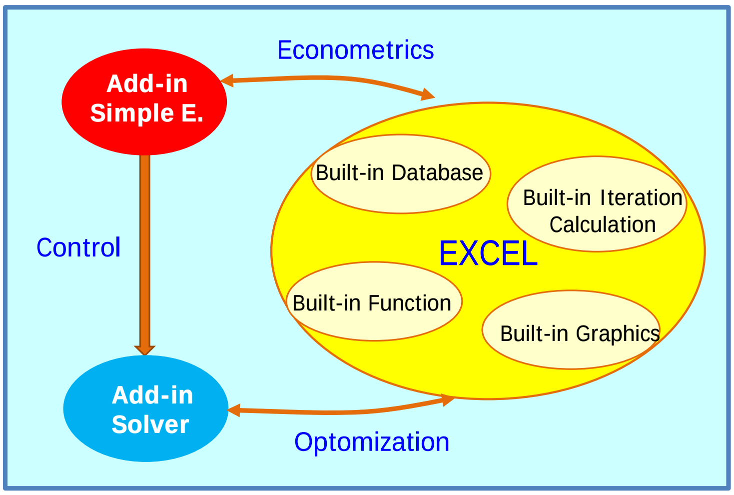


Figure 3.3.2 Model Construction Environment using Microsoft Excel and Add-in "SimpleE"

Based on the above approach, we have constructed an optimization model to seek for solutions for best mix of energy and power supply sources. The detail of the model is explained in Chapter 4. From the researches on the preceding studies, we take in those major variables in the model that will impact long term economic growth of the whole ASEAN region. On the individual countries, we have considered specific features and conditions of these countries relating to energy, such as market-economy, planned-economy, subsidies and taxes, etc., existing institutions, and their long-term strategies and so on, and have conducted analytical simulation on the following points;

a. what kind of policies will be necessary or preferable in order to establish a desired energy supply structure
b. what will be their impact on energy tariff and environment
c. what will be their impact on the regional energy security

With the above study, we have aimed to formulate policy recommendations supported by quantitative analyses.

3.4 Analytical Simulation and Recommendation

Using the above energy mix model and the power supply mix model, we have run simulations as explained below. Simulations are conducted, in principle, as an optimization approach, assuming such variables like government subsidy, tax, export/import amount, etc., as external variables that can be controlled by policies, and policy objectives as the objective function. Candidate of the objective function are minimization of supply cost, CO_2 emissions, import amount and other elements, individually or combined. The style and value of the objective function are finalized analyzing the outcome of iterated simulation, and with consultation with Castalia and JICA. The relationship of the assumptions and objective functions given there and the resultant solutions obtained is illustrated in the Figure 3.4.1 below.

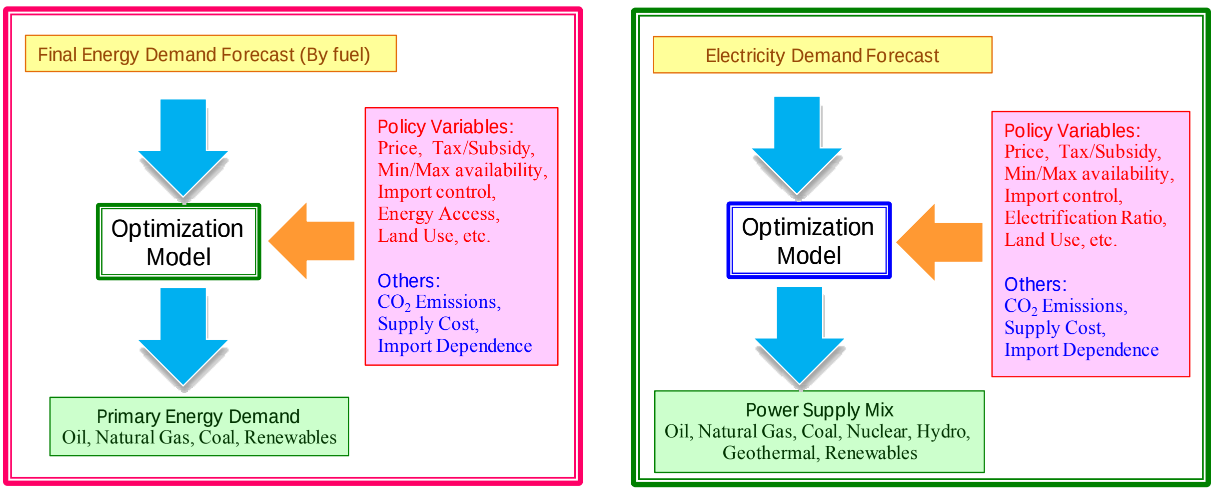


Figure 3.4.1 Concept of Analytical Simulation

In this Study, we have concentrated on the simulation on the electricity sector. Major contrasting points being considered and assessed in this Study are as discussed below.

a. Market economy vs. planned economy

In our model, we express the difference between a market economy and a planned economy by way of defining certain variables that are decided through market activities in case of a market economy, such as prices and supply quantities, as external variables and assign certain values as if being politically decided. In addition, it is necessary to fabricate important factors into the model, such as various costs, energy efficiency, transformation efficiency, CO_2 emissions, technology progress, etc., as given conditions. Impact of changes in these important factors may be examined as case studies, giving different parameters to the variables in concern.

b. Low-carbonization vs. energy efficiency

With regard to low-carbonization, principal options as variables are mainly found in the supply side such as institutional introduction of renewable energies, fuel shift to natural gas and biofuel, and switch to EV. In case of energy efficiency, however, in addition to the supply side variables such as energy efficiency of power plants and motor vehicles, there are also options simultaneously in the demand side such as change of industrial structure toward a less energy intensive direction, improvement of energy efficiencies of various appliances, and so on. We should carefully handle these. In this Study, we consider that changes in industrial structure are already examined in the given demand forecast, and we concentrate on policy variables to improve energy transformation efficiency on the supply side.

In actual application, we adopt a method as flexible as possible in handling these variables so that they can be easily revised reflecting the progress of the study. Then, it should be noted that, as electricity is a single medium to fulfill electricity demand, the rest of the energy demand has multiple media for supply, such as solid, liquid or gaseous fuels for transportation demand. In the latter case, we often find that demand is linked to supply, or demand is subject to supply constraints. In order to consider such phenomenon, we may have to link the demand forecasting model and the supply optimization model as much as possible.

Chapter 4 Power Mix Optimization Model and Major Assumptions

Based on the concept structured in Chapter 3, the Study Team has developed a model to simulate the optimum power generation mix under given conditions. Its structure and operating procedure are illustrated in Section 4.1. Major assumptions on various elements of power generation, costs and fuel prices to be externally given to the model are set out as explained in Section 4.2. Various scenarios are set out changing external conditions as shown in Section 4.3 for evaluation of policy options. Under these settings, simulation was run for Vietnam, Indonesia, the Philippines and the whole ASEAN region; the results are analyzed in Chapter 5.

4.1 Model Structure and Simulation Process

The model prepares a mechanism to link policy variables and power planning integrating technical and economic relationships and processes among various elements in the power supply system, such as future electricity demand, costs and fuel prices and other external assumptions into a consistent system. With this setting, the model can simulate the optimum power mix properly, and be able to evaluate effect of certain policies conducting comparative analysis of different scenarios. Important policy variables to be considered in the model are, on the supply side, energy mix in the power generation, investment costs, fuel prices, and, on the demand side, electricity tariff, national income, etc.

4.1.1 Framework of Model

Figure 4.1.1 shows the conceptual diagram of the power mix model.

At first, as a preparatory procedure to set out scenarios to be examined by the model, various external conditions relating to electricity supply should be analyzed and quantified as input for the model. They are as shown on the left side of the chart outside of the model box; firstly, specific policy conditions such as control on electricity tariff, FIT, subsidies and taxes relating to electric power industry operation; secondly, general institutional framework such as regulations and policy priorities, ex., fuel import/export control, target energy/power mix, control of fuel prices, current status and future target of rural electrification, and other regulations and policy priorities for the power industry; thirdly, economic and energy outlook and important indices for the objective period such as GDP and energy demand. Based on these assumptions, electricity demand schedule for the entire objective period should be projected by sector for different tariff schedules such as for household, industry, etc. This is the first assessment; later, such demand schedule will be further adjusted in the model reflecting changes in the electricity tariff in the process of optimization.

Incorporating these pre-studies on general circumstances and more prominent factors, major conditions as quantified values shall be set out on the external variables which will be incorporated into the model. Most important elements on the supply side are the minimum and maximum allowable capacities of each plant, its capital cost, thermal efficiency, plant life and other operational parameters. Fuel prices and fuel availability constraints are also important factors as well as the electricity demand schedule.

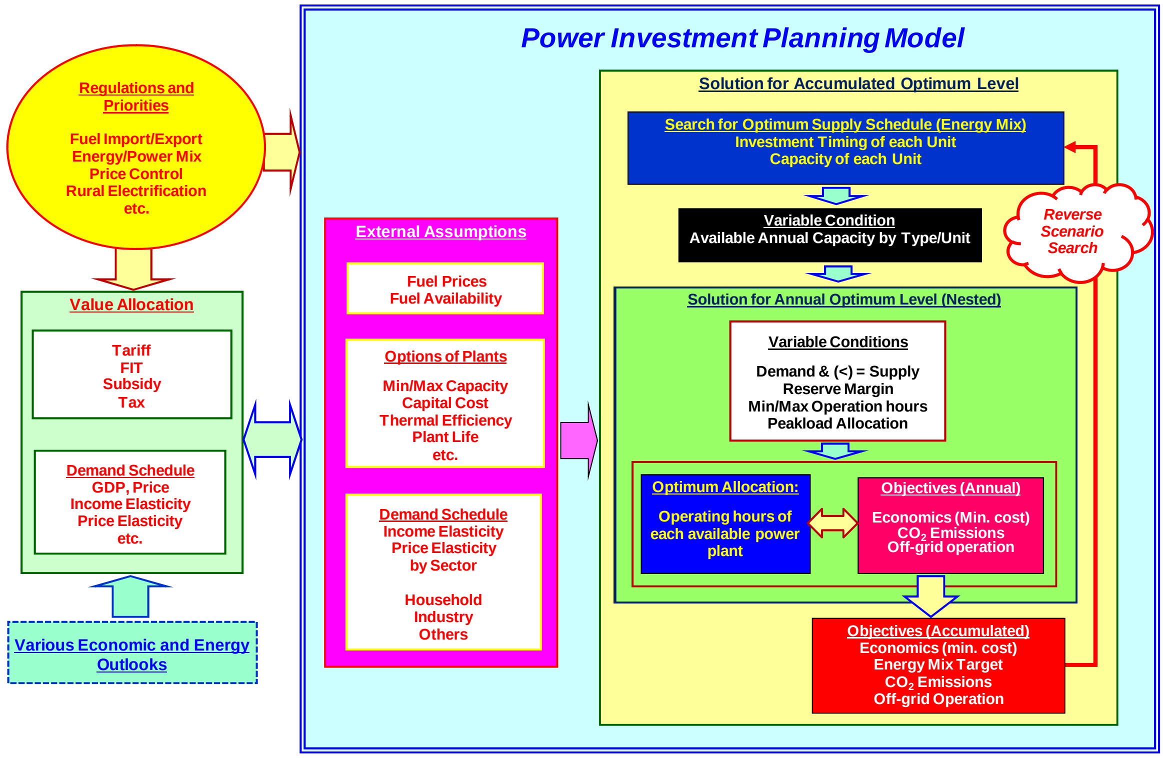


Figure 4.1.1 Conceptual Diagram

Given these assumptions, the model is designed to search for optimum supply schedule including investment timing and capacity of each plant considering available annual capacity, reserve margin, minimum/maximum operation hours, peak load allocation and other important elements against the objectives such as economics (i.e., minimum cost), GHG emissions target, etc. After iteration of optimization trial for annual and the resultant accumulated outcome, the model will eventually find the solution for the accumulated optimum level of power mix for the entire objective period.

As above, the model is constructed to incorporate various elements and these are processed to reach an optimum solution. To examine effects of different scenarios, the model should be run repeatedly for each scenario changing assumptions. Then, differences in the outcome shall be analyzed to evaluate various policy options.

The fundamental framework of the model is prepared as follows:

a. Scope of output: annual power mix by energy and plant type from 2014 to 2050
b. Platform software: Microsoft Excel and Simple E.
c. Optional Power mix: 21 types of plants of various energy sources including oil, natural gas, coal, hydro, geothermal, renewable (such as PV, Wind, and Biomass), and nuclear.

d. Each power plant type is characterized by the source of energy with typical size in generating capacity, investment cost, utilization rate, and ability to respond to peak and/or intermittency, as listed in Table 4.2.1 and 4.2.2.

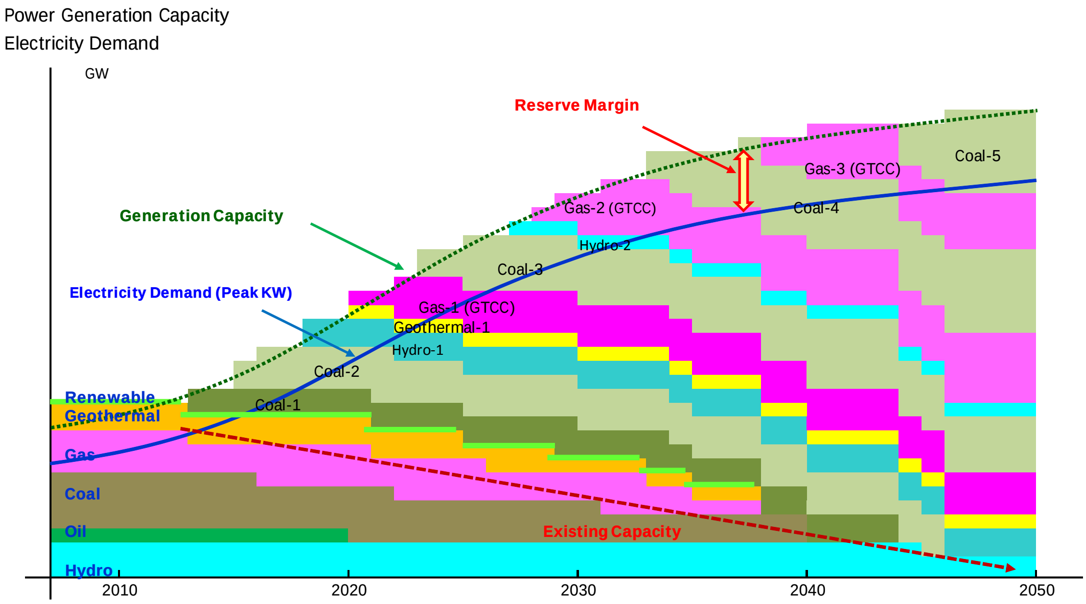


Figure 4.1.2 Image of Selecting Optimum Combination of Power Plants

Figure 4.1.2 shows the image of selecting the optimum combination of power plants via the model, while the model is designed to simulate the optimum power mix only for the additional requirement. Fundamental elements are the existing capacity that phase out gradually, electricity demand in quantity (GWh) and level at peak (GW), and reserve margin. Against this backdrop, most suitable plants are selected to satisfy the demand one after another under given various conditions. Selected plants are locked-in in the power mix and continue to be operated through their technical life. The accumulated amount of the objective function for the whole objective period will be optimized via iterated simulation.

4.1.2 Simulation Mechanism and Basic Parameters

In this model, the simulation process to select the optimum power mix is set out as below. The model operates taking account of specific features of the important model parameters as well as external conditions set out up-front.

1) Based on the given demand schedule and the existing supply capacity, while the existing plants are assumed to phase out gradually, the required annual addition of new plants is estimated in the manner to satisfy both the peak and base load requirements. This calculation also takes account of the reserve margin and peak loads given as external variables; under the standard condition, the model assumes a 20% of reserve margin and a 10% of peak allocation out of the GWh basis demand amount. These numbers would be a bit different from the present status in Indonesia; it is

necessary to check them in due course to reflect realistic local conditions.

2) The load levels for both the base and peak hours in each year are calculated in relation to the total demand amount in GWh. The capacity requirement (in GW) is estimated by applying a load factor as an external variable; in the model 0.75 is applied for the Philippines and Vietnam while 0.78 for Indonesia.

3) The required numbers of various plants for each year are selected from among 21 types of power plants covering fossil fuel thermal plants to renewable energy sources and in different capacities as explained in the next section.

4) Selection and decision of the required number of plants of each type are made in the order from the cheapest one to meet the demand, and controlled by the annual maximum limit given to each plant type in view of physical construction capacity in each country. This is to consider the difficulty to construct a number of big plants simultaneously due to constraints on availability of appropriate sites, engineering workforce, etc.

5) If the electricity demand for certain year cannot be met by adding the maximum allowed number of the cheapest plant, then the next cheapest plant will be selected until the total supply reaches the demand or the maximum additional capacity allowed for the selected plant type. If the demand is not met fully, this selection procedure to pick up the subsequently cheapest plant continues until the demand is fully satisfied.

6) If a plant is newly constructed in certain year, the economics of each plant in that year is calculated assuming that it afterwards operates for its whole technical life (specified years are set out for each plant type) with given cash flow of CAPEX and OPEX.

7) CAPEX includes capital investment costs, financial cost, and policy variables like investment subsidies and/or taxes. The current assumption for CAPEX is temporally derived from several case studies previously run for Indonesia. In actual application, CAPEX must be reviewed carefully incorporating specific features in each country. This part can be used to simulate the impact of favorable interest rates in financing or weighted average cost of capital (WACC).

8) OPEX will be affected by changes in fuel prices, annual operation and maintenance (O&M) cost, as well as other policy variables like tax and subsidies. (Current assumptions on these parameters are temporary ones, but are made to be at a reasonable level for Indonesia according to a study previously run by the IEEJ). This part of the model taking in the annual variable cost can be used for the simulation of FIT in a form of reducing the operating cost.

As shown in the Figure 4.1.2, the above calculation made for each year will be accumulated for the whole objective period. Then, reverse scenario search will be run via solver until the optimum solution is reached.

Supply-Demand Interaction

In order to consider the supply-demand interaction that will arise as electricity tariff will be adjusted through iterating calculation, the following adjustment mechanism is installed in the model.

1) At the beginning, a demand function is prepared in correlation to income (national or sectoral income as the case may be), electricity tariff, and other variables. At present, however, energy conservation factor is not yet incorporated in the model.

2) The income and tariff are linked through elasticity and they are variable. Therefore, simulation would incur different outcome for the original assumptions as electricity tariff and other elements will be readjusted through simulation. This may result in a different demand schedule and thus result in different energy mix in the future.

3) The tariff level and other variables can be linked to the supply side results such as OPEX of each year. This can trigger the link between demand and supply through simultaneous calculation. Currently, elasticities are set in linear in the model.

As above, the final solution reflects effect of supply-demand interaction incurred by iterating calculation.

Considerations on Environmental Parameters

Environmental parameters such as emissions levels of CO_2, NO_X, and Particulate Matter (PM) from each plant type are calculated applying parameters based on the data obtained from existing researches. Thus, the model can evaluate amount of their emissions for a given scenario. The model is also able to simulate a case where constraints are given to the emissions of pollutants. Data and information on these environmental factors need to be re-adjusted or updated from time to time considering the specification of available fuels, specific plant types to be engaged in future and effects of technology advancement.

4.1.3 Operating Model for Policy Assessment

The Power Mix Optimization Model is developed on an Excel spread sheet, and a part of the sheet is used to control the simulation, which is between the rows around 60 to 140 of the Sheet 1. Other part of Sheet 1 is used for input of external conditions and output of the simulation result. Giving external conditions as model inputs, the model will be run to search for the optimum power mix. Under the given set of assumptions, the model will produce outcome on various elements, which will be analyzed to evaluate effects of different policy options. Major assumptions and outputs for consideration are as listed below.

Scenario assumptions as input

To prepare for running model, numerical assumptions should be set out at first on major policy factors as listed below to define certain scenario, in addition to common general assumptions, and be input into the model. Different scenarios can be set out changing these assumptions.

a. Control on demand such as energy conservation target

b. Constraints on energy mix, number of available plants and type, etc., including assumptions on nuclear and renewable energies

c. Fuel price, with or without regulations, subsidies or import duties

d. Specification of plants, such as low- or high-efficiency plants, operating patterns, and necessity of complimentary plants in case of variable renewables

e. Taxes and subsidies on fuels, CAPEX and OPEX

f. Interest rate/ Discount rate

Simulation results as output

Then, the model shall be run and yield major outputs of the simulation as follows:

1) Indicators of affordability such as total cost, total revenue, total subsidies/taxes, social cost as total government outflow, and unit electricity cost, etc.

2) Power mix in capacity (GW) and generation amount (GWh), and shares by energy

3) Share of low carbon energies, emissions of CO_2, NO_X, and PM

For conduct of analysis on policy options, there are two opposite ways of approach to use the model. One is to set a scenario as assumptions and obtain the resultant outcome for analysis. The other is to set targets on simulation results and find a required scenario on key variables through model simulation.

A. Set a scenario (assumptions) and see the impacts on simulation results

In this type of approach, assumptions or constrains are set out at first typically on the following elements:

1) Energy savings potential, harnessing future demand, and impacts of determinants such as electricity tariff, income/price elasticity, sectoral demand shares, etc.

2) Energy mix target, introduction of nuclear and renewable energy, overall cost target, control on tariff and tariff structure, and control on GHG emissions

3) Future fuel prices and fuel price disparities

4) Tax and/or subsidies on fuel, CAPEX and/or OPEX under applicable financial support, feed-in-tariff, capital subsidies, etc.

5) Merit order, instead of least cost allocation for future energy mix

Then, the model shall be run and the outcome shall be evaluated in absolute values or in comparison with outcome of other scenarios.

B. Set targets on simulation results and find the required scenario

This type of approach typically includes:

1) Find tariffs, and/or future elasticity to reduce electricity demand to a target
2) Find tariffs, and/or future elasticities to balance the costs and revenues, to realize the targeted affordability level
3) Find scenarios to reduce CO_2 emissions, and/or others variables.
4 Find required financial supports - fuel taxes, capital subsidies, or FITs - to realize the target of introducing PV, Wind, etc.; or, in other words, to reduce fossil fuel consumption such as coal, oil to a target level.

The method of approach as above may be selected according to the subject or issues to be focused in the analysis.

4.2 Assumptions for Simulation

4.2.1 Electricity Demand

The electricity demand for the Reference Case is prepared for the period up to 2050, based on the projections adopted for the IEEJ's latest study "Asia/World Energy Outlook 2013", as shown in Table 2.4.7 in Chapter 2. In the model, the overall electricity demand is divided in three categories for household, industry and others. The electricity demand of the base year of each sector is projected by income and price elasticities, which are different among sectors. Elasticities can be changed by an annual escalation or reduction factor. Then, the projected sectoral demands are aggregated and readjusted to the whole demand as projected by comprehensive study as above. This process is prepared to reflect structural changes in demand with different tariff schedules among sectors in the revenue structure of the power sector.

For examination of an energy conservation case, a reduced electricity demand schedule is given to the model applying a hypothetical energy conservation rate.

4.2.2 Power Plant Specification

For simulation of power generation mix, this model adopts seven energy types of plants with three variations. The selected energy types are oil, gas, coal, hydro, geothermal, renewables and nuclear. Three variations are assumed for each fuel type except for renewables in terms of the plant capacity, CAPEX, OPEX, and thermal efficiency. For renewables, three variations are adopted for different resources; i.e., biomass, wind and solar photovoltaic.

Technical, operational as well as economic assumptions are set out for each plant type as shown in Table 4.2.1 and 4.2.2. For thermal plants burning fossil fuels and nuclear plants, the maximum plant factor is set at 80% or maximum operation of 7,000 hours a year, after considering regular maintenance work. For hydro, they are set at 50% or 4,380 hours in view of seasonal fluctuation of water resources. For variable renewables such as wind and solar PV, they are set at a considerably low level around 20% in view of resource availability.

Thermal efficiencies under standard conditions are assumed at relatively high level for gas- and coal-fired thermal stations as various advanced technologies such as Combined Cycle Gas Turbines (CCGT) and Super- and Ultra-super Critical (SC, USC, A-USC) coal thermal are now available. They are 5-15% higher compared with the existing plants and being further upgraded. On the other hand, only small low-efficient plants are listed for oil-thermal, which are mostly diesel driven. In view of the substantial price disparity among oil, natural gas and coal, large scale oil fired plants are no more competitive, but only small units may be used for limited purposes such as distributed generation for remote small grids or peaking.

Table 4.2.1 Technical Features of Power generation by Type

Energy and Plant Type	Capacity	Life	Max. Operating Hours	Max. Capacity Factor	Min. Operating Hours	Min. Capacity Factor	Thermal Efficiency	Priorities	
								Base/ Middle	Peak
	MW	years	hrs/year		hrs/year		%		
Oil	10	20	7,000	80%	0	0%	30	10	1
	20	20	7,000	80%	0	0%	35	10	1
	50	20	7,000	80%	0	0%	36	10	2
Natural Gas									
Open Cycle	300	25	7,000	80%	1,000	11%	45	10	2
Combined Cycle	700	25	7,000	80%	1,000	11%	50	10	3
Combined Cycle	1,000	25	7,000	80%	1,000	11%	60	10	3
Coal									
Super Critical	500	35	7,000	80%	3,000	34%	35	10	10
Advanced Super Critical	1,000	35	7,000	80%	3,000	34%	40	10	10
IGCC	1,000	35	7,000	80%	3,000	34%	45	10	10
Hydro									
Small Hydro	10	30	4,380	50%	0	0%	100	10	1
Small Hydro	20	30	4,380	50%	0	0%	100	10	1
Conventional Hydro	100	30	4,380	50%	0	0%	100	10	1
Geothermal	50	30	6,132	70%	3,000	34%	100	10	10
	100	30	6,132	70%	3,000	34%	100	10	10
	200	30	6,132	70%	3,000	34%	100	10	10
Biomass	10	20	3,500	40%	3,000	34%	20	10	5
Wind	50	20	2,028	23%	0	0%	100	10	2
Solar PV	10	20	1,752	20%	0	0%	100	10	1
Nuclear	1,000	40	7,000	80%	3,000	34%	100	10	20
	1,500	40	7,000	80%	3,000	34%	100	10	20
	2,000	40	7,000	80%	3,000	34%	100	10	20

Economic features of each plant type are given in Table 4.2. The initial overnight capital cost (CAPEX) and non-fuel operation and maintenance cost (OPEX) of each plant are cited from an IEEJ's previous study for Indonesia. Estimates of capital cost for power generating plants are so diverse among regions and analysts[36], it is necessary to upgrade them reviewing global market

[36] IEA and ERIA World Energy Outlook 2013 Special Report "Southeast Asia Energy Outlook", September 2013. The IEA and US EIA also provide such information with a wide range of differences.

conditions for engineering and procurement of equipment as well as local conditions for site preparation and construction. On the CAPEX, an annual rate of *Cost Escalation or Reduction* is given to each plant to consider technology advance and/or increasing scarcity of potential sites. The *Maximum Number of Plants Constructed* in a year is given for each plant type in view of engineering and workforce constraints. A number smaller than 1.0 indicates that only one such plant can be built in several years time due to long lead time or other constraints. A *Weighted Average Cost of Capital (WACC)* is also incorporated to evaluate impact of financial cost for investment. *Emissions Factors* are prepared to calculate emissions amount of pollutants in each scenario. In addition, a merit order is given for each plant to define order of selection. For these detail assumptions, please refer to the model.

Table 4.2.2 Economic Features of Power generation by Type

Energy and Plant type	Total CAPEX	Weighted Average Cost of Capital	Annual Escalation/Reduction	Total Non-Fuel OPEX	CO2 Emission Factor	NOx Emission Factor	PM Emission Factor	Max. No. of Plant Construction
	$/kW			$/kWh	ton/toe	kg/toe	kg/toe	plants/yr
Oil	500	0.06	1.00	0.0260	0.79	50.2416	0.5443	50
	800	0.06	1.00	0.0260	0.79	50.2416	0.5443	50
	900	0.06	1.00	0.0260	0.79	50.2416	0.5443	50
Natural Gas								
Open Cycle	718	0.06	1.00	0.0075	0.58	11.7230	0.2093	5
Combined Cycle	847	0.06	1.00	0.0065	0.58	11.7230	0.2093	5
Combined Cycle	1164	0.06	1.00	0.0055	0.58	11.7230	0.2093	5
Coal								
Super Critical	1441	0.06	1.00	0.0060	1.04	12.5604	1.6747	5
Advanced Super Critical	1590	0.06	1.00	0.0060	1.04	12.5604	1.6747	5
IGCC	1892	0.06	1.00	0.0060	1.04	12.5604	1.6747	1
Hydro								
Small Hydro	2000	0.06	1.01	0.0041	0	0	0	0.63
Small Hydro	1600	0.06	1.01	0.0041	0	0	0	0.63
Conventional Hydro	1000	0.06	1.01	0.0041	0	0	0	0.63
Geothermal	7000	0.06	1.01	0.0180	0	0	0	0.2
	5000	0.06	1.01	0.0180	0	0	0	0.2
	2567	0.06	1.01	0.0180	0	0	0	0.2
Biomass	1500	0.06	1.00	0.0043	0	0	0	20
Wind	2200	0.1	0.99	0.0170	0	0	0	5
Solar PV	3500	0.1	0.99	0.0250	0	0	0	500
Nuclear	4500	0.06	1.00	0.0195	0	0	0	1
	3800	0.06	1.00	0.0165	0	0	0	1
	3200	0.06	1.00	0.0152	0	0	0	1

4.2.3 Fuel Cost

Fuel cost is an important factor in the selection of plant type, as total amount spent for fuel over the plant life far exceeds the capital expenditure and non-fuel operating cost except for peaking plants. Therefore, in addition to the disparity among fuel prices, import duties, fuel tax and fuel subsidies significantly distort the power mix selection.

Fuel cost assumptions except nuclear is adopted from the IEEJ's assumptions for "Asia/World Energy Outlook 2013," while that for nuclear power is cited from the IEA "Projected Costs of

Generating Electricity" 2010 Edition. In the model, fuel prices are projected starting with the present prices in the base year as estimated in Table 4.2.3, and projected by an annual escalation rates adopted in the IEEJ's forecast. As natural gas is presently priced extremely high in the Asian market, it is estimated to decline reflecting the impact of shale gas from North America to be introduced in the form of LNG.

Table 4.2.3 Assumptions for the Future Fuel Prices

Fuel	Unit	Current Price	Current Price in oil equivalent	Annual Growth Rate
			US$/toe	%
Crude Oil	US$/Bbl	115	782	0.36
Fuel Oil (Crude Oil x 1.05)			821	0.36
Natural Gas	US$/MMBtu	16.7	710	-0.53
Coal	US$/ton	134	82	0.28
Nuclear	US$/MWh	9.33	109	0

Although the above automatic price escalation mechanism is installed in the model, which applies a uniform escalation rate for the entire projection period, it is also possible to input different price scenarios with non-linear changes, giving digital numbers of prices for each year. Using this price input mechanism, it is possible to assess impact of fuel taxes and subsidies changing price input data.

In conducting assessment of price effect, it should be noted that all the settings are generally made in real terms. However, inflation rates may be different among various elements. Therefore, it is important to carefully examine consistency of the relationship among various elements such as CAPEX escalation/reduction rate, WACCs, and fuel prices.

4.3 Scenario Setting

A list of low carbon and energy efficiency policies is given in Table 4.3.1, which summarizes policy types and corresponding assumptions, policy variables as inputs for the model, elements to be evaluated relating to short term and long terms impacts, objective functions, bearer of cost and intended policy effect. Cost borne by users means that such cost may be passed through to users via cross subsidy. Cost borne by the government means that such cost may be expended out of the government budget, or accumulated as deficit at state company and eventually borne by the government in a form of financial support.

For evaluation of LC&E policies, this table illustrates the relevant factors for scenario setting and the elements to show the resultant impacts. For more detail discussion on LC&E policies in Vietnam, Indonesia and the Philippines and their effects, please refer to the detail examination of policies for the simulation analysis summarized in Appendix-A.

Table 4.3.1 Diagram of LC&E Policies, Policy Controling Factors and Value Factors for Evaluation

<table>
<tr><th rowspan="2">Policy Type
Description</th><th rowspan="2">Policy Variables as Input</th><th colspan="2">Impacts</th><th rowspan="2">Who bears cost?</th><th rowspan="2">Intended Policy Effect</th></tr>
<tr><th>Short term</th><th>Long term</th></tr>
<tr><td>1. Renewable Portforlio Standard
% of RE in total generation</td><td>1. Schedule of RPS % by RE
2. Cost of RE
3. Quantity (kWh) of RE</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff</td><td rowspan="8">1. Energy demand and supply

2. Energy mix and power development plan

3. Power cost

4. Power tariff</td><td>Users</td><td>Lower Carbon</td></tr>
<tr><td>2. Feed-in Tariff
Payment for RE</td><td>1. FIT rates on generation by RE
2. Cost of RE
3. Quantity (kWh) of RE</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff</td><td>Users or Government</td><td>Lower Carbon</td></tr>
<tr><td>3. Natural Gas Pipeline
PPP or public investment</td><td>1. Pipeline cost
2. Time schedule
3. Location
4. Avaiability of gas for power</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff</td><td>Users or Government</td><td>Lower cost and lower carbon</td></tr>
<tr><td>4. Coal Import/Export Restriction
Removing restrictions</td><td>1. Coal price
2. Time schedule
3. Cheaper coal for power generaton</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff</td><td>Users or Government</td><td>Lower/higher cost and higher/lower carbon</td></tr>
<tr><td>5. Distributed Generation
(Expansion of off-grid RE)
Payment for RE to DG</td><td>1. Time schedule
2. Cost of RE
3. Quantity (kWh)
4. Electrificaton Ratio</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff
4. Diesel fuel saving</td><td>Users or Government</td><td>Lower carbon Electrification</td></tr>
<tr><td>6. Building Code
Energy Audits, ESCO</td><td>1. Time schedule
(Improvement of EE)
2. Increase of buildings
(Future demand schedule)</td><td>1. Total cost
2. Total supply/demand
(saving)
3. Electricity tariff</td><td>Users</td><td>Lower carbon and lower cost</td></tr>
<tr><td>7. Grid Integration
Ramp-up of plant size
Reduction in losses
Reduction in reserves margin</td><td>1. Location
2. Time schedule</td><td>1. Total cost
2. Total supply/demand
(saving)
3. Electricity tariff
4. Load curve (load factor)</td><td>Users</td><td>Lower carbon and lower cost</td></tr>
<tr><td>8. Labelling and Standard
Minimum energy performance standard (MEPS)</td><td>1. Time schedule
(Improvement of EE)
2. Quantity (kWh)</td><td>1. Total cost
2. Total supply/demand
3. Electricity tariff</td><td>Users</td><td>Lower carbon and lower cost</td></tr>
<tr><td colspan="6">Shared Assumptions
1. Long term demand schedule including population, urbanization, economic growth, industrial structure, etc.
2. Costs for plant CAPEX, OPEX, fuel, RE, T&D, etc.
3. Financial cost (WACC)
4. Technology advance
5. Regional grid integration status</td></tr>
<tr><td colspan="6">Objective functions
1. Total accumulated net cost/benefit (including governmet out-cash flow and impact on national income)
2. Total reduction in GHG emissions
3. Increase of energy access/electrification ratio</td></tr>
</table>

Based on this table, we have set up the schedule to evaluate cost and benefit of LC&E policies for the electric power sector in ASEAN countries. Starting with the Reference scenario (BAU: Business as Usual case), several scenarios are set to consider impacts of policy actions on the following issues;

1) Energy Saving

2) GHG reduction

3) Desirable generation mix

4) Effect of FIT and/or fuel subsidy reduction

5) Different fuel prices

To identify combinations of main policies and their variations, a matrix is prepared as shown in Table 4.3.2. Starting with the Reference Case simulation, impacts of these policies are simulated for Vietnam (V), Indonesia (I) and the Philippines (P). For the whole ASEAN countries, only a limited number of cases are run for reference.

Table 4.3.2 Selection of Scenarios

Variations \ Policies	Reference	Generation Mix Target	Feed-in Tariff (FIT)	GHG Reduction
Business As Usual (BAU)	VIP	VIP	VIP	VI
Fule Export Restriction	I			
Subsidy (Fuel and/or Tariff)	VIP	VIP	VIP	VIP
Energy Efficiency	VP	VP	VP	V
Least Cost	VIP			
Special Option (Nuclear)	VI			

Outcome of these analytical simulations are explained in the following chapter.

Chapter 5 Outcome of Simulation Analyses for ASEAN Countries

This chapter illustrates outline of the simulation results on various policy options. Based on the assumptions and method of approach developed in Chapter 4, simulations were run for Vietnam, Indonesia, and Philippines as well as for the whole ASEAN region. At first the Reference scenario was run and then various policy scenarios were run for evaluation of their implications and impacts. From these outputs, our much simplified model looks producing logical consequences. However, we should note that data and assumptions given to the model for each scenario are still preliminary ones, and it is necessary to upgrade them before we proceed to the next step for substantive discussion on energy policy planning. In particular, more accurate data and information on the local conditions are essential.

In addition, it is also necessary to examine whether the indicated pathway during the projection period for each scenario is sound and sustainable. We need to fine tune the model in this regard.

5.1 Vietnam

Table 5.1.1 shows a summary of simulation results on various scenarios for Vietnam; Reference scenario, Least Cost scenario, Generation Target scenario, CO_2 Reduction scenario, Fuel Subsidy scenario, Feed-in Tariff scenario, and Thermal Efficiency scenario. Accumulated total cost means summation of generation and transmission & distribution costs from 2014 to 2050. The accumulated total revenue means a sum of electricity sale from 2014 to 2050. Therefore, the balance of the total cost and the total revenue shows profits and/or losses for power business. If National Power Company (EVN) cannot make a profit, the government or someone else may have to cover the loss.

All scenarios run for Vietnam incur a big amount of losses during the early part of the projection period, as the electricity tariff is assumed to increase at annual 3% from the present very low level. For most of the projection period, the revenue will be lower than the cost for generation, transmission, and distribution as calculated by the model. In the case of Vietnam, the calculated unit costs in 2030 for the Reference Scenario is US cents 10.39/kWh while the electricity tariff reaches only US cents 9.60 by that year according to the present assumption. In 2050 it falls between US cent 7.95/kWh and US cent 10.85/kWh while the electricity tariff reaches US cents 11.42/kWh.

As only a summary of the aggregate cost calculation is shown in Table 5.1.1, it is highly questionable if the above pathway for the cost/tariff structure is sustainable.

Table 5.1.1 Summary of Scenarios for Vietnam

		Reference (BAU)	Least Cost	Generation Target	CO2 Reduction	Fuel Subsidy	Feed-in Tariff	High Efficiency
Amount till 2050								
Total Cost	bil. US$	1,602	1,242	1,551	1,696	1,570	1,602	1,457
Total Revenue	bil. US$	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Profit	bil. US$	38	398	89	-56	70	38	183
Profit Mark-up Ratio	%	102	132	106	97	104	102	113
Subsidies incuding FITs	bil. US$	0	0	0	0	-32	-0	0
Gov't Total Net Inflow	bil. US$	38	398	89	-56	70	38	183
Tariff & Cost								
Electricity Tariff (2030)	¢/kWh	9.60	9.60	9.60	9.60	9.60	9.60	9.60
Electricity Tariff (2050)	¢/kWh	11.42	11.42	11.42	11.42	11.42	11.42	11.42
Unit Cost (2030)	¢/kWh	10.39	7.89	9.44	7.82	10.21	10.39	9.17
Unit Cost (2050)	¢/kWh	10.25	7.95	9.93	10.85	10.05	10.25	9.33
Electricity Demand (2050)	TWh	1,190	1,190	1,190	1,190	1,190	1,190	1,190
Cumulative Additional Electricity Generation	TWh	15,626	15,626	15,626	15,626	15,626	15,626	15,626
Cumulative Additional Fossil Fuel Consumption	Mil.toe	3,109	2,589	2,794	2,079	3,109	3,109	2,510
Coal	Mil.toe	2,395	2,589	2,634	952	2,395	2,395	2,183
Oil	Mil.toe	0	0	160	15	0	0	0
Natural Gas	Mil.toe	714	0	0	1,112	714	714	327
CO_2 Emissions	Mil.t-c	2,905	2,693	2,866	1,647	2,905	2,905	2,460
Fossil-Fuel Intensity	kg/kWh	0.199	0.166	0.179	0.133	0.199	0.199	0.161
Generation Mix (2030)								
Coal	%	51.2%	57.5%	61.4%	40.6%	51.2%	51.2%	60.9%
Oil	%	1.0%	1.0%	2.9%	1.0%	1.0%	1.0%	1.0%
Natural Gas	%	33.6%	10.4%	10.4%	23.3%	33.6%	33.6%	20.1%
Hydro	%	14.2%	31.2%	9.3%	33.3%	14.2%	14.2%	18.0%
Nuclear	%	0.0%	0.0%	10.1%	1.9%	0.0%	0.0%	0.0%
Geothermal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Biomass	%	0.0%	0.0%	6.0%	0.0%	0.0%	0.0%	0.0%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Generation Mix (2050)								
Coal	%	65.3%	73.3%	63.7%	14.8%	65.3%	65.3%	71.4%
Oil	%	0.1%	0.1%	7.6%	1.5%	0.1%	0.1%	0.1%
Natural Gas	%	28.5%	1.6%	1.6%	71.7%	28.5%	28.5%	18.4%
Hydro	%	6.0%	25.0%	1.8%	11.4%	6.0%	6.0%	10.1%
Nuclear	%	0.0%	0.0%	11.8%	0.6%	0.0%	0.0%	0.0%
Geothermal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Biomass	%	0.0%	0.0%	13.6%	0.0%	0.0%	0.0%	0.0%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Details of these scenarios are explained in the following sections.

5.1.1 Reference Scenario

In the Reference Scenario, amount of power generation in Vietnam for 2050 is projected to reach almost the same quantity of the present power generation in Japan.

a. Power generation from gas-fired power plants is kept at the current level as far as possible.

b. Power generation from hydro-power plants cannot exceed the presently estimated resource potential.

c. Nuclear power plant will be introduced from 2020 as a given condition.

It is also assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.1.1 shows the generation mix at least cost calculated under the above constraints. In 2050, most of power generation comes from coal-fired power plants (65.3%), followed by gas-fired power (28.5%), hydro power (6.0%), and oil-fired power (0.1%).

Then the accumulated total cost and accumulated total revenue till 2050 are US$1,602 billion and US$1,640 billion respectively, with a deficit of US$38 billion. The accumulated CO_2 emissions till 2050 will reach 2,905 million C-tons.

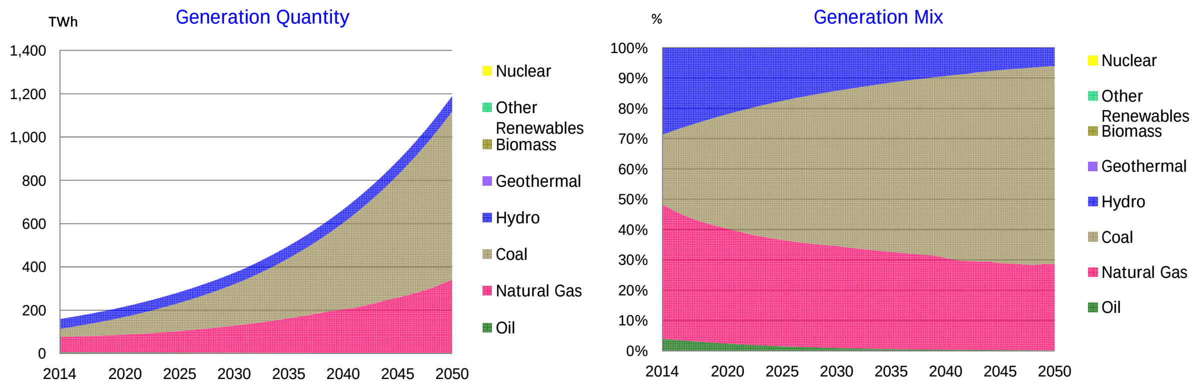


Figure 5.1.1 Reference Scenario: Vietnam

5.1.2 Least Cost Scenario

In this scenario, amount of power generation in 2050 in Vietnam is same as the Reference scenario. Other major assumptions are;

a. Power generation from gas-fired power plants shall not be at the current level.

b. Power generation from hydro-power and geothermal plants should not exceed the present resource potential.

c. Power generation by nuclear is assumed to start from 2020 as a given condition.

It is also assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.1.2 shows the generation mix of the ***Least Cost Scenario*** arrived at least cost under the above constraints. In 2050, most of the power generation will be supplied by coal-fired power plants (73.3%), followed by hydro power (25.0%), gas-fired power (1.6%), and oil-fired power (0.1%).

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$1,242 billion and US$1,640 billion respectively, with a surplus of US$398 billion. The accumulated CO_2 emission till 2050 reaches 2,693 million C-tons.

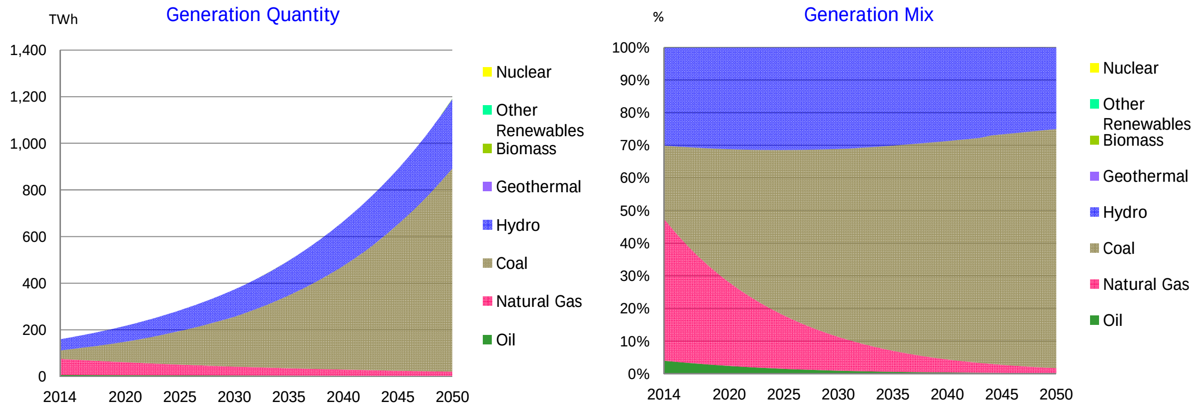


Figure 5.1.2 Least Cost Scenario: Vietnam

5.1.3 Generation Target Scenario

According to the National Master Plan of Vietnam for Power Development for the 2011 - 2020 Period with the Vision to 2030, the total capacity of power plants is scheduled to be about 75,000 MW in 2020, of which hydropower accounts for 23.1%, pumped storage hydropower accounts for 2.4%, coal thermal 48.0%, and natural gas thermal 16.5% (including LNG for 2.6%); power using renewable energy accounts for 5.6%, nuclear power 1.3% and power import 3.1%. Electricity supply schedule is projected in the Master Plan as below:

a. In 2020, the produced and imported amount of electricity will be about 330 billion kWh, of which hydropower accounts for 19.6%, coal 46.8%, natural gas thermal power 24.0% (including LNG 4.0 %); power using renewable energy accounts for 4.5%, nuclear power 2.1% and imported power 3.0%.

b. In 2030, the total power plant capacity will increase to 146.8 GW, of which hydropower accounts for 11.8%, pumped storage hydropower 3.9%, coal thermal 51.6%; and natural gas thermal 11.8% (including LNG 4.1%); power using renewable energy 9.4%, nuclear power 6.6%, and imported power 4.9%.

c. Electricity output in 2030 will be 695 billion kWh, of which hydropower accounts for 9.3%, coal thermal 56.4%; natural gas thermal 14.4% (including LNG 3.9%); power using renewable energy 6.0%, nuclear power 10.1%, and imported power 3.8%.

In this scenario, the amount of power generation in 2050 is same as projected for the Reference scenario. Constraints are given on the generation mix targets as; 9.3% for hydro, 6.0% for renewable and 10.1% for nuclear in 2030. It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014. Other constraints are the same as given in the Reference scenario.

Figure 5.1.3 shows the generation mix at least cost calculated under the above constraints. In 2050, most of the power generation comes from coal-fired power (63.7%), followed by biomass power (13.6%), nuclear power (11.8%), oil-fired power (7.6%), hydro power (1.8%), and natural gas-fired power (1.6%). Coal thermal plants will accelerate dominance in the power mix reflecting the cheaper fuel costs compared with other energy sources.

The accumulated total cost and accumulated total revenue till 2050 will be US$1,551 billion and US$1,640 billion respectively, with a surplus of US$89 billion.

The accumulated CO_2 emissions till 2050 will reach 2,866 million C-tons, further increasing from the Reference scenario.

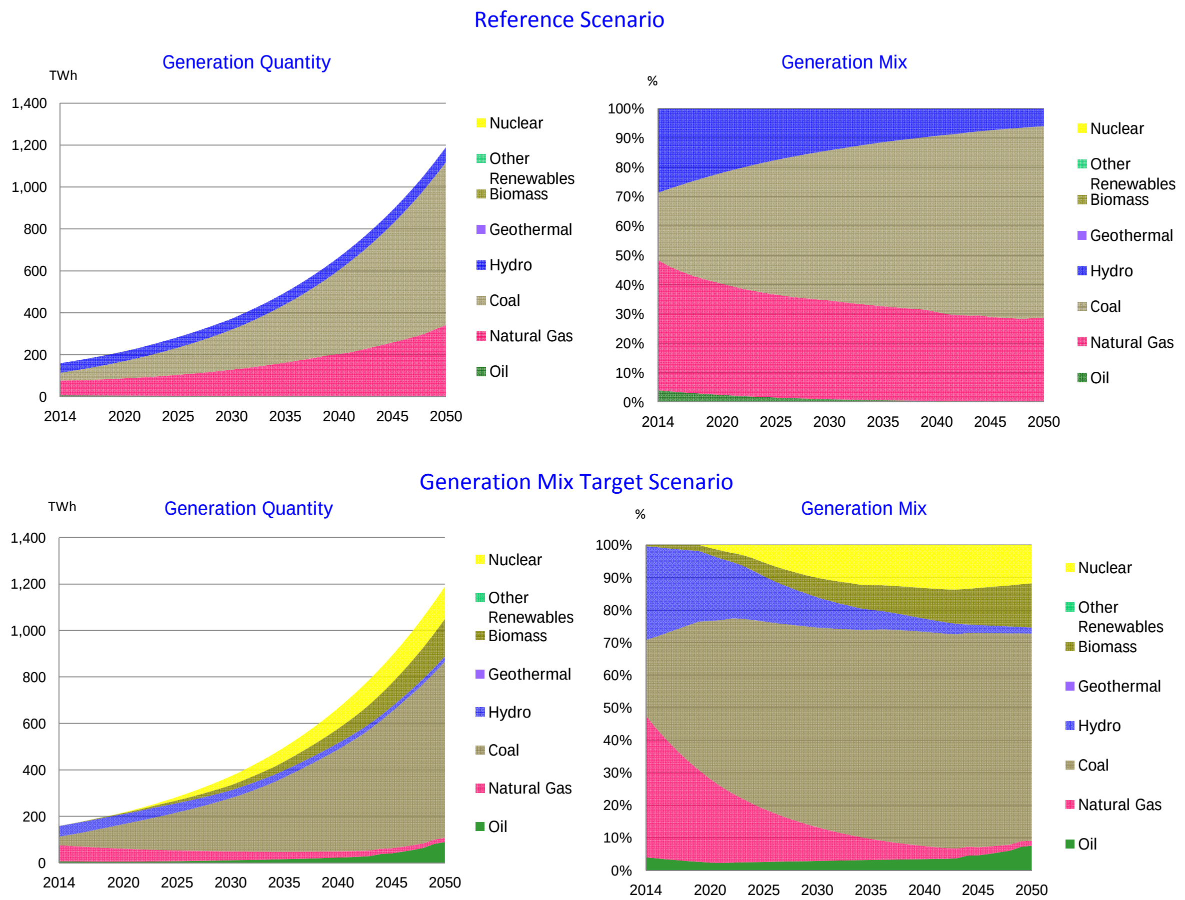


Figure 5.1.3 Generation Target Scenario: Vietnam

5.1.4 CO_2 Reduction Scenario

Vietnam has GHG emission reduction targets. Decision No. 1393/QĐ-TTg; the National Green Growth Strategy was approved by the Prime Minister on 25 September 2012. Outline of the Green Growth Strategy is as follows.

a. The period 2011-2020: Reduce the intensity of greenhouse gas emissions by 8-10% as compared to the 2010 level; reduce energy consumption per unit of GDP by 1-1.5% per year. Reduce greenhouse gas emissions from energy activities by 10% to 20% compared to the business as usual case. This commitment includes a voluntary reduction of approximately 10%, and an additional 10% reduction with additional international support.

b. Orientation towards 2030: Reduce the annual greenhouse gas emissions by at least 1.5-2%; reduce greenhouse gas emissions in energy activities by 20 to 30% compared to the Business As Usual (BAU) projection. Of this commitment, the voluntary reduction will be approximately 20%, and another 10% is dependent on additional international support.

c. Orientation towards 2050: Reduce greenhouse gas emissions by 1.5-2% per year.

The greenhouse gas consists of carbon dioxide, methane, nitrous oxide, and fluorinated gas. Among them, only carbon dioxide (CO_2) can be controlled by the energy sector. Therefore, in this scenario, we set carbon dioxide (CO_2) emissions constraints as follows.

1) 15% reduction by 2020 compared to BAU

2) 25% reduction by 2030 compared to BAU

3) 45% reduction by 2050 compared to 2010 BAU

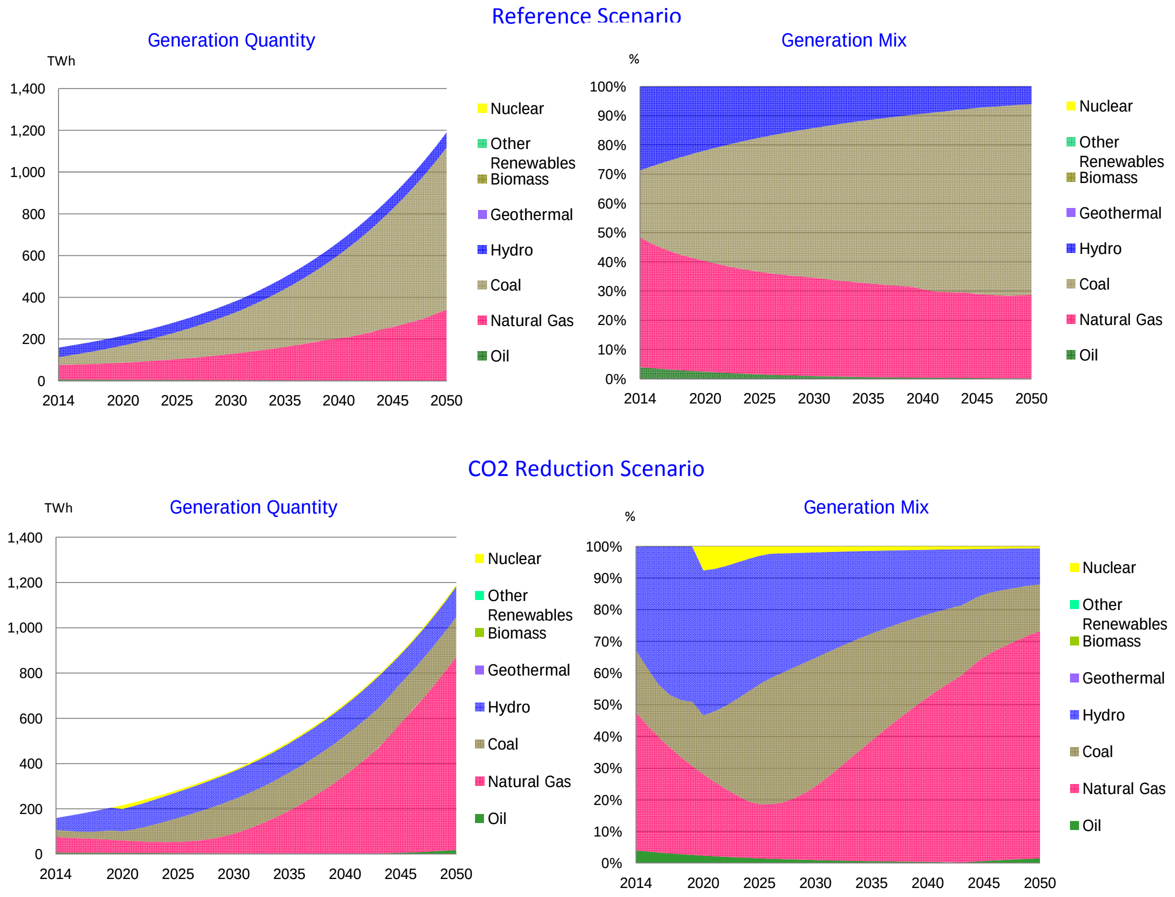


Figure 5.1.4 CO_2 Reduction Scenario: Vietnam

Figure 5.1.4 shows the generation mix at least cost calculated under the above constraints. In 2050, all the low-carbon power sources need to be mobilized fully so that most of the power generation will be supplied by gas-fired power (71.7%), followed by coal-fired power (14.8%), hydro power (11.4%) oil-fired power (1.5%), and nuclear power (0.6%).

It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Then, the accumulated total cost and accumulated total revenue till 2050 are US$1,696 billion and US$1,640 billion respectively, with a deficit of US$56 billion. The accumulated CO_2 emissions till 2050 will reach 1,647 million C-tons, which is only 56%of the emissions amount to be exhausted under the Reference scenario. Compared with the Reference scenario, coal consumption will be significantly reduced. Instead, all low-carbon generation will be mobilized extensively, in particular natural gas.

5.1.5 Fuel Subsidy Phase-out Scenario

In this scenario, coal price for coal-fired power plants provides subsidy at 15% of coal price because current coal price for power plants is set 15% lower than market price. Other assumptions are the same as Reference scenario.

Figure 5.1.5 shows the generation mix of the Fuel Subsidy Scenario Phase-out scenario arrived at least cost under the above constraints. Generation mix is the same as Reference scenario. If coal-fired power plants get more subsidies at 30% or more, the share of coal generation will be further increased.

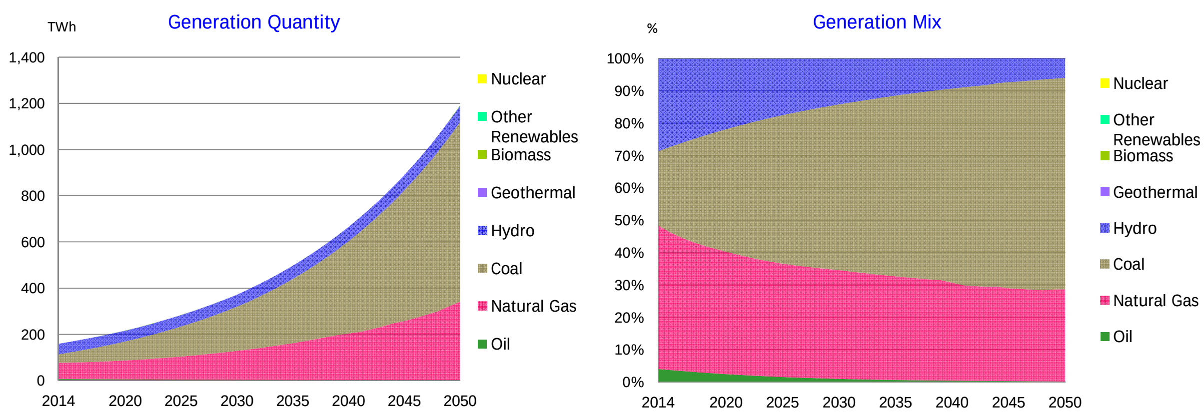


Figure 5.1.5 Fuel subsidy Phase-out Scenario: Vietnam

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$1,570 billion and US$1,640 billion respectively, with a surplus of US$70 billion. But subsidy of US$32 billion is needed. The accumulated CO_2 emission till 2050 is also the same as

Reference scenario.

5.1.6 Feed-in Tariff scenario

To promote renewable energy introduction, Vietnam is considering introduction of Feed-in Tariff (FIT) system for wind energy and biomass-CHP (combined heat and power). In this scenario, feed-in tariffs are set at US$0.078/kWh for wind and US$0.056/kWh for biomass. Other assumptions are the same as the Reference scenario.

Figure 5.1.6 shows the generation mix at least cost calculated under the above constraints. Generation mix is the same as the Reference scenario. Despite the introduction of FIT system, generation amount by biomass and wind would not be introduced since the FIT system does not work well as the absolute level of the electricity tariff is too low or as their resources are limited compared with other fuels. This issue must be looked into more in detail.

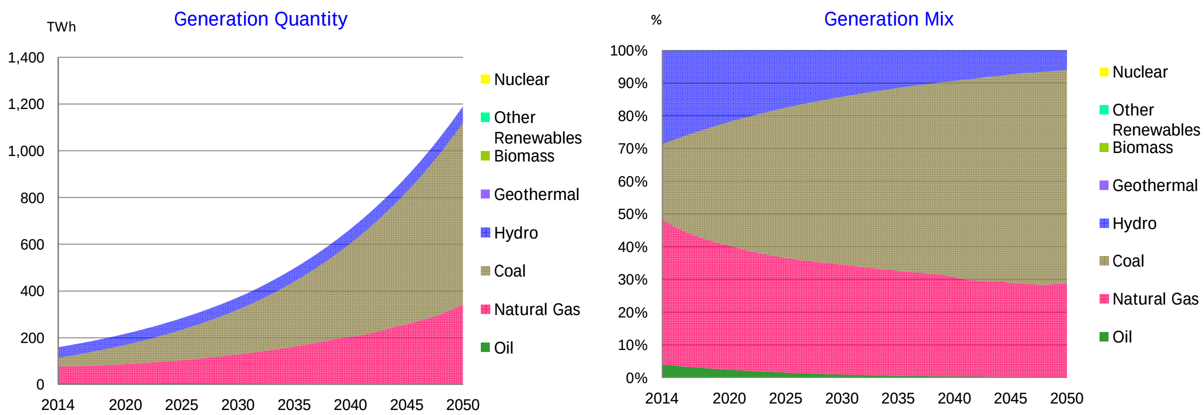


Figure 5.1.6 FIT Scenario: Vietnam

5.1.7 Thermal Efficiency Scenario

In this scenario, amount of power generation in 2050 is assumed same as derived under the Reference scenario. Constraints are given on the thermal efficiency targets; that is, 60% for gas-fired power plants and 45% for coal-fired power plants. Other constraints are same as applied for the Reference scenario.

Figure 5.1.7 shows the generation mix of the Thermal Efficiency scenario arrived at least cost under the above constraints. In 2050, most of the power generation will be supplied by coal-fired power plant (71.4%), followed by gas-fired power (18.4%), hydro power (10.1%), and oil-fired power (0.1%).

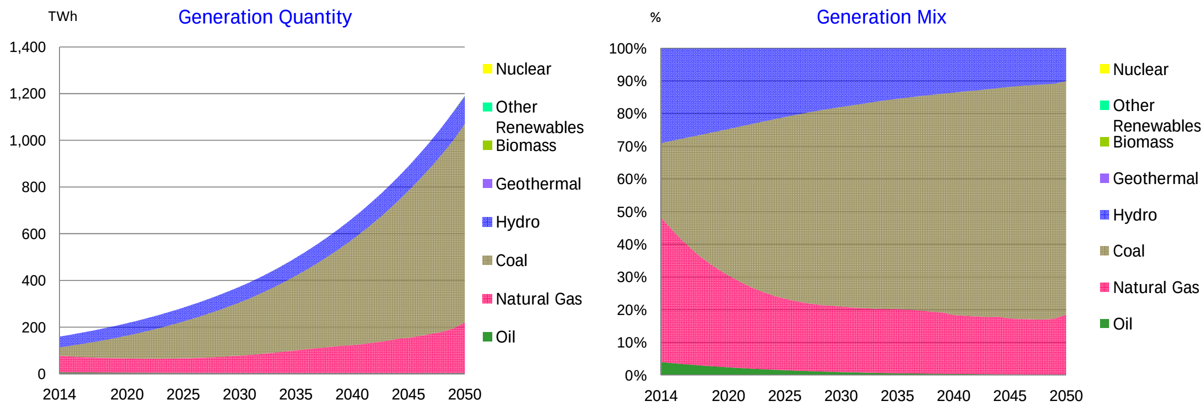


Figure 5.1.7 Thermal Efficiency Scenario: Vietnam

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$1,457 billion and US$1,640 billion respectively, with a surplus of US$183 billion. The accumulated CO_2 emission till 2050 reaches 2,460 million C-tons. With higher thermal efficiency, fuel consumption for the whole projection period will be reduced 598 million toe or 19.3%, and CO_2 emissions 445 million C-tons or 15.4%. Total cost will be reduced $144 billion or 9% instead of higher financial cost. For the fast growing economy of Vietnam, adoption of best available technologies (BAT) will be most beneficial in the long run while a greater amount of initial investment fund should be prepared.

5.2 Indonesia

Some of the simulation results for Indonesia are summarized in the Table 5.2.1. The accumulated total cost of supply is the cumulative total cost for power generation, transmission and distribution over the projection period from 2014 to 2050, while the accumulated revenue means the cumulative revenue from rate collection through 2050. In countries where the electricity tariff is regulated (usually lower than cost), the investment for power generation, transmission and distribution is hard to be recovered by the sale of electricity. Therefore, utility companies need government's subsidies to maintain business; this significantly distorts proper investment decisions. In this exercise, the total accumulative fiscal cost for electricity subsidy is estimated under the assumption that all the losses caused by electricity tariff regulation shall be borne by the government.

Table 5.2.1 Simulation Results: Indonesia

Policy set		Reference	Fuel Export Restriction	Tariff Subsidy Reduction	Least Cost	Feed-in Tariff	Generation Mix	GHG Reduction
Amount till 2050								
Total Cost	bil. US$	3,077	2,951	2,963	2,718	3,079	3,145	3,303
Total Revenue	bil. US$	2,075	2,075	2,898	2,075	2,075	2,075	2,075
Profit	bil. US$	-1,003	-877	-64	-643	-1,004	-1,070	-1,228
Profit Mark-up Ratio	%	67.4%	70.3%	97.8%	76.3%	67.4%	66.0%	62.8%
Subsidies incuding FITs	bil. US$	0	0	0	0	-23	0	0
Gov't Total Net Inflow	bil. US$	-1,003	-877	-64	-643	-1,004	-1,070	-1,228
Tariff & Cost								
Electricity Tariff (2030)	¢/kWh	8.14	8.14	12.07	8.14	8.14	8.14	8.14
Electricity Tariff (2050)	¢/kWh	8.30	8.30	12.12	8.30	8.30	8.30	8.30
Unit Cost (2030)	¢/kWh	12.21	11.88	12.07	11.06	12.20	12.70	12.78
Unit Cost (2050)	¢/kWh	12.25	11.88	12.12	10.43	12.24	11.93	13.43
Electricity Demand (2050)	TWh	1322	1322	1281	1,322	1322	1322	1322
Additional Electricity Generation	TWh	1272	1272	1231	1,272	1272	1272	1272
Additional Fossil Fuel Consumption	Mil.toe	3,262	3,453	3,164	4,892	3,198	1,973	2,404
Coal	Mil.toe	2,351	2,353	2,345	4,877	2,279	1,257	590
Oil	Mil.toe	0	0	0	0	0	0	0
Natural Gas	Mil.toe	911	1,100	820	15	918	717	1,814
CO_2 Emissions	Mil.t-c	2,973	3,085	2,914	5,081	2,903	1,723	1,666
Fossil-Fuel Intensity	kg/kWh	0.15	0.16	0.15	0.23	0.15	0.09	0.11
Generation Mix (2030)								
Coal	%	51.2%	51.2%	52.6%	84.4%	49.4%	31.9%	20.7%
Oil	%	2.5%	2.5%	2.6%	2.5%	2.5%	2.5%	2.5%
Natural Gas	%	26.8%	35.1%	24.9%	4.7%	26.9%	20.4%	47.5%
Hydro	%	10.0%	9.9%	10.2%	7.4%	10.0%	16.6%	16.6%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	7.1%	0.9%	7.3%	0.9%	7.8%	12.1%	6.8%
Biomass	%	2.3%	0.3%	2.3%	0.0%	3.3%	9.9%	5.8%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%	6.5%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Generation Mix (2050)								
Coal	%	51.7%	51.7%	53.3%	93.1%	51.2%	31.9%	14.6%
Oil	%	0.5%	0.5%	0.6%	0.5%	0.5%	0.5%	0.5%
Natural Gas	%	29.4%	35.7%	27.4%	2.1%	29.3%	23.1%	60.4%
Hydro	%	9.5%	6.6%	9.7%	3.6%	9.5%	16.1%	14.9%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	4.9%	2.8%	4.9%	0.2%	5.0%	10.9%	1.5%
Biomass	%	4.0%	2.7%	4.1%	0.5%	4.4%	10.5%	8.0%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

In the above simulation, natural gas price for Indonesia is assumed differently from the other two countries, as shown in the following table, since ample natural gas is available in Indonesia and delivered at much cheaper prices.

Table 5.2.2 Natural Gas Price Assumption for Indonesia

Present Price		Annual Escalation	
		～2030	～2050
$/MMBTU	$/toe	%	%
10.0	425.1	1.9	0.28

5.2.1 Reference Scenario

In the Reference (BAU) scenario there are no targets assumed for GHG reduction or renewable energy promotion. Electricity tariffs for the end users are assumed to be set by the government. Over the projection period, the average electricity tariff is assumed to increase at an annual rate of 1% from the current level (8 cent/kWh). The fuel costs in this scenario and in other scenarios except the Fuel Export Restriction scenario are calculated based on international fuel prices excluding natural gas. Though there is no specific target for power generation technology, the composition of power generation mix in this scenario with least cost option while considering constraints on resource potential is maintained more or less similar with the current one. It is, however, assumed that there will be no new installation of oil-fired thermal power plants.

Table 5.2.3 Power Generation Mix in 2011 and August 2013

	Share (%)	
	2011	Aug, 2013
Oil	23.20	12.60
Natural Gas	20.34	23.46
Coal	44.41	51.54
Hydro	6.81	7.80
Geothermal	5.14	4.51
Biofuels and Waste	0.11	0.09
Solar/Wind/Other	0.00	0.00
Nuclear	0.00	0.00

Source: IEA World Energy Statistics and Balances 2013, and MEMR Indonesia

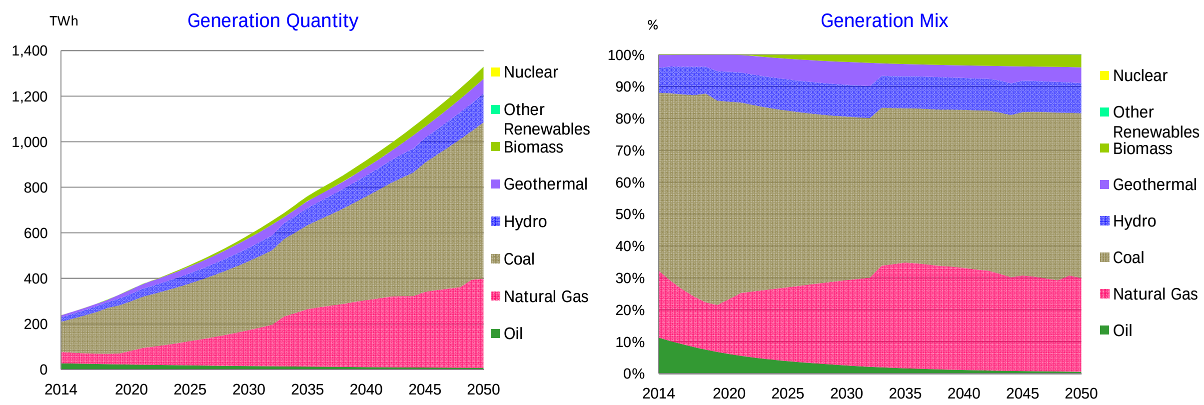


Figure 5.2.1 Power Generation Mix: Reference Scenario

Under the Reference scenario, the share of oil power generation will decrease over the projection period (from 12.6% in 2013 to 2.5% in 2030 and further down to 0.5% in 2050). Renewable energy, including hydro power, is expected to play a larger role in the future power generation portfolio (from 12.4% to 19.3% in 2030 and down slightly to 18.4% in 2050 because of constraints of resource potential). Because of the phasing out oil power and the limited growth of renewable power, shares of natural gas thermal and coal thermal power generation will increase moderately from their current levels.

Through 2050 the cumulative generation cost (including fuel cost) is estimated to be 3,077 billion US dollars while the cumulative revenue from electricity tariff collection is 2,075 billion US dollars, which means that until 2050 there will be 1,003 billion US dollars of deficit, which will amount to 5% of GDP. The revenue covers only two thirds of the cost. Cumulative GHG emissions from the new power generation fleet under the Reference scenario are estimated to be 2,973 million C-tons (energy originated GHG emission in till 2011 is about 402 million C-tons).

5.2.2 Fuel Export Restriction

This scenario is based on a draft policy “DEN Proposed Coal and Gas Export Restrictions”. Because of rapid increase of domestic consumption, Indonesia is anticipated to become an importer of natural gas in the medium- to long-term. The policy calls on the government to restrict coal and natural gas exports in order to preserve them for long term domestic use. If the export restriction is imposed, the fuel cost is supposed to become cheaper. Under this scenario costs of coal and natural gas were changed below international prices (80% of those under the Reference scenario).

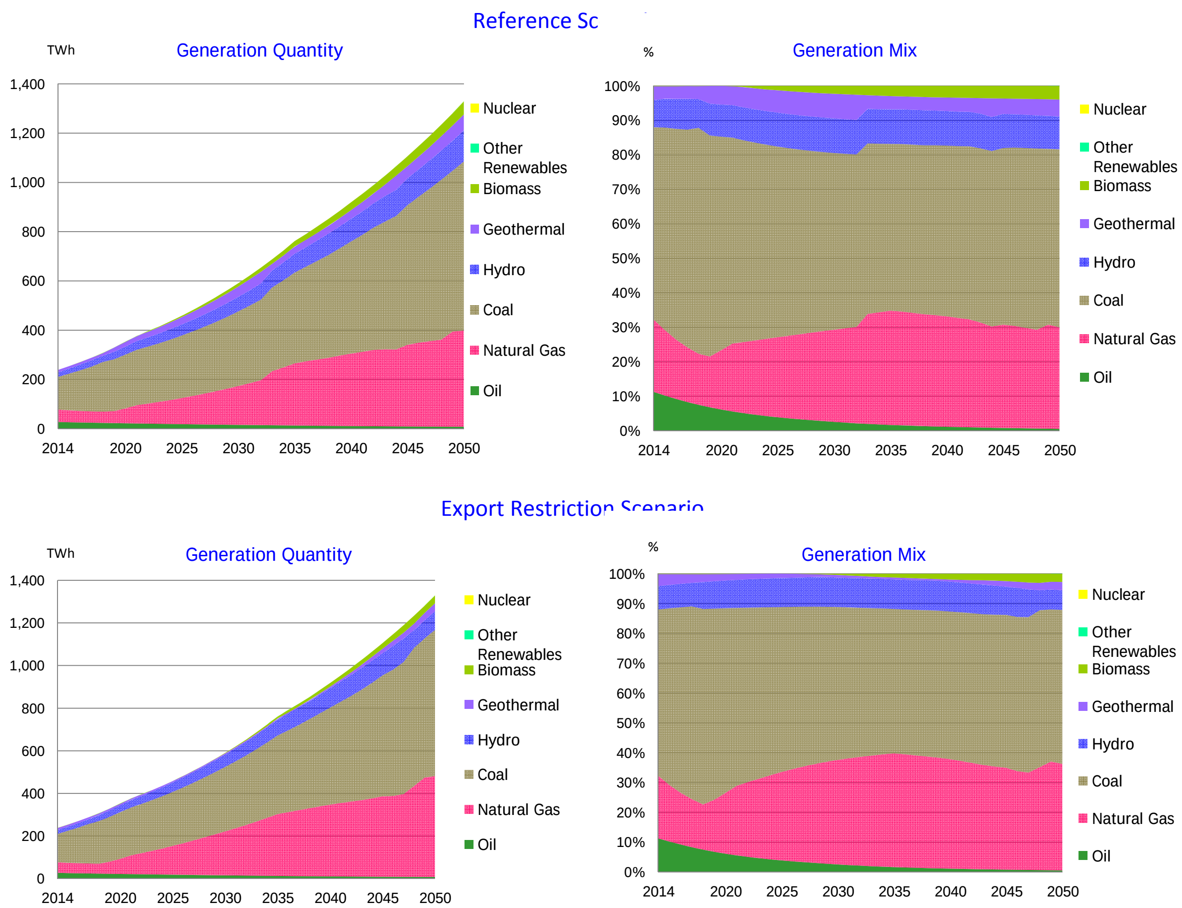


Figure 5.2.2 Power Generation Mix: Fuel Export Restriction Scenario

Under the Fuel Export Restriction scenario, the share of oil power generation is kept same as that under the Reference scenario (from 12.6% in 2013 to 2.5% in 2030 and further down to 0.5% in 2050). The share of natural gas generation will be 35.1% in 2030 and will increase slightly to 35.7% in 2050. The share of coal power generation is expected to become 51.2% in 2030 and up to 51.7% in 2050. The share of power generation from renewable energies will be squeezed by fossil fuels, slightly down from 12.4% in 2013 to 11.1% in 2030 and then up moderately to 12.7% in 2050.

Under this scenario, through 2050 the cumulative generation cost (including fuel cost) is estimated to be 2,951 billion US dollars. The cost is lower than that under the Reference scenario because of lower fuel costs. The cumulative revenue from electricity tariff collection is 2,075 billion US dollars, same as that under the Reference scenario. As a result, until 2050 there will be cumulative 877 billion US dollars of deficit. Cumulative GHG emissions from the new power generation fleet under the Fuel Export Restriction scenario is estimated to be 3,085 million C-tons, higher than that under the Reference scenario due to increased power generation by fossil fuels.

5.2.3 Tariff Subsidy Reduction Scenario

Under the Tariff Subsidy Reduction scenario, subsidy for electricity tariff will be gradually phased out, which means that electricity tariff for end users will be allowed to gradually increase in order to reflect the real generation cost. Other conditions are same as the Reference scenario.

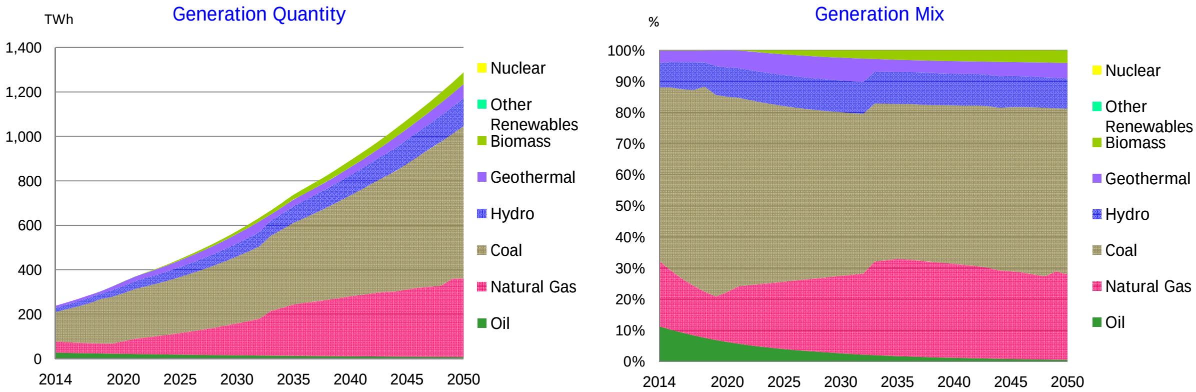


Figure 5.2.3 Power Generation Mix: Subsidy Reduction Scenario

Under this scenario, consumers will be exposed to a higher electricity tariff and are expected to react to the tariff increase by reducing electricity consumption. As a result, the total electricity demand under this scenario will be smaller by 3.1% than that under the Reference scenario. Electricity demand under subsidy reduction scenario is 1,281TWh in 2050, while under the Reference scenario the demand is 1,322TWh in 2050.

As same with other scenarios, there would be no additional oil power generation coming online under this scenario, and the share of oil power generation will decrease over the projection period. The share of natural gas generation is expected to be 24.9% in 2030 and increase moderately to

27.4% in 2050. The share of coal power generation will increase from 52.6% in 2030 to 53.3% in 2050. Renewable energies including hydro power is projected to contribute 19.8% to the generation mix in 2030 while their share will go down to 18.7% in 2050.

Under this scenario, through 2050 the cumulative generation cost including fuel expenditure is estimated to be 2,963 billion US dollars, lower than that under the Reference scenario because of the smaller demand. The cumulative revenue from electricity tariff collection is 2,898 billion US dollars, which means until 2050 there will be 64 billion US dollars of deficit. The deficit is much smaller than that under the Reference scenario because electricity tariff is allowed to increase gradually to reflect generation cost. However, the average electricity tariffs to end users are 12.07 cent/kWh in 2030 and 12.12 cent/kWh in 2050, much higher than those under the Reference scenario, 8.14 cent/kWh in 2030 and 8.30 cent/kWh in 2050. The amount of cumulative GHG emissions from new power generation is 2,914 million C-tons slightly lower compared to 2,973 million C-tons under the Reference scenario.

5.2.4 Least Cost Scenario

Under the Least Cost scenario, the constraint for power generation mix is removed, which means that power generation option with the least cost would be selected to meet electricity demand. Other conditions including resource potential of renewable energy are assumed same.

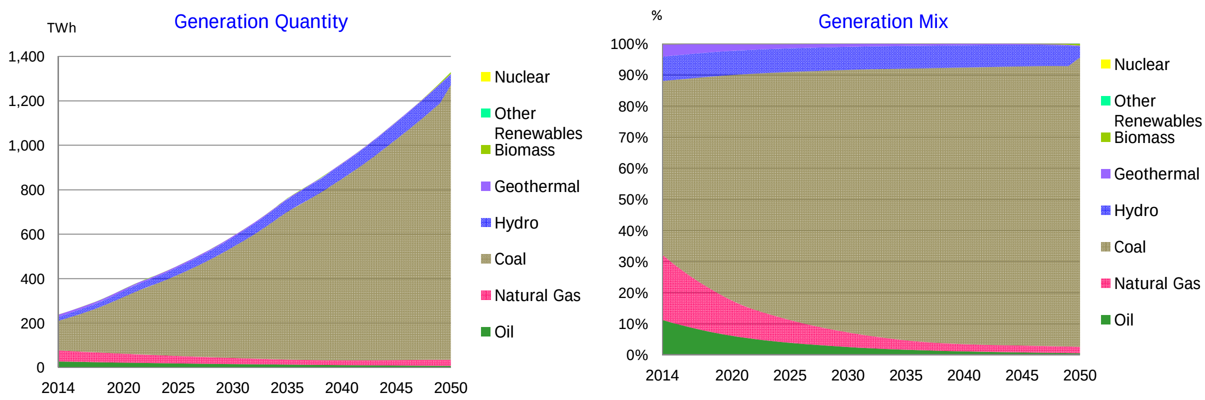


Figure 5.2.4 Power Generation Mix: Least Cost Scenario

Under the Least Cost scenario, the share of oil power generation is same as that under the Reference Scenario. Since generation option is selected based on least cost, not surprisingly a chunk of the generation mix comes from cheaper coal-fired thermal power plants. The share of coal power is expected to be 84.4% in 2030 and further goes up to 93.1% in 2050. On the other hand, natural gas power generation, the generation cost of which is higher, will play an extremely limited role under the Least Cost scenario. The share of natural gas is projected to decrease to 4.7% in 2030, and further goes down to 2.1% in 2050. The share of renewable power generation will also be squeezed by coal-fired thermal power. The share of renewable energies including hydro power is expected to decrease to 8.3% in 2030 and further down to 4.3% in 2050.

Under the Least Cost scenario, through 2050 the cumulative generation cost (including fuel cost) is estimated to be 2,718 billion US dollars, the lowest among all the scenarios. The cumulative revenue from electricity tariff collection is 2,075 billion US dollars, which means until 2050 there will be 643 billion US dollars of deficit. Cumulative GHG emissions from the new power generation will be largest among all the scenarios, 5,081 million C-tons until 2050.

5.2.5 Feed-in-Tariff

Under the Feed-in-Tariff scenario, the Feed-in Tariffs for renewable energy are set as follows:

- Geothermal: 0.11USD/kWh (phase out in 5 years)
- Biomass: 0.1466USD/kWh (phase out in 5 years)
- Wind: 0.15USD/kWh (phase out in 5 years)
- PV: 0.1637USD/kWh (phase out in 10 years)

Purchase period was set to be 20 years. It is assumed that the cost of FIT would be paid by the government.

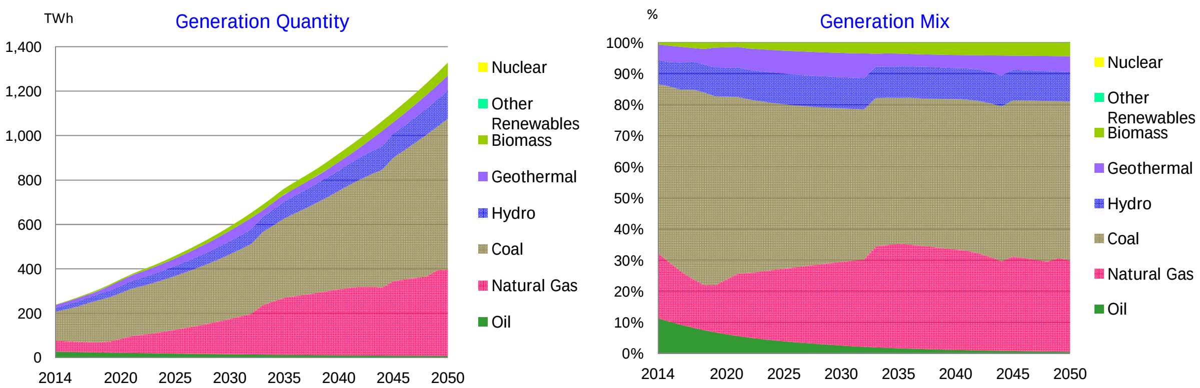


Figure 5.2.5 Power Generation Mix:FIT Scenario

Since total electricity demand is unchanged and there is no new installation of oil power plants, share of oil power under the FIT scenario and the Reference scenario are same. Shares for coal and natural gas are expected to be 49.4% and 26.9%, respectively, in 2030 and 51.2% and 29.3%, respectively, in 2050. Renewable energy will play a greater role under the FIT scenario than under the Reference scenario. Share of renewable power including hydro will be 21.1% in 2030 but will go down to 18.9% in 2050 because the purchase of renewable power will finish by 2050.

Under this scenario, through 2050 the cumulative generation cost (including fuel cost) is estimated to be 3,079 billion US dollars, higher than that under the Reference scenario. The cumulative revenue from electricity tariff collection is 2,075 billion US dollars, which means until 2050 there will be 1,004 billion US dollars of deficit. The total cost of FIT is estimated to be 23 billion US dollars. Cumulative GHG emissions from new power generation will be less than that under the Reference scenario, 2,903 million C-tons compared with 2,973 million C-tons under the Reference scenario.

5.2.6 Energy Mix Scenario

The Energy Mix Scenario is developed based on the "KEN 2050 (Indonesian Energy Scenario to 2050 by the Indonesian National Energy Council or Kebijakan Energi Nasional)".

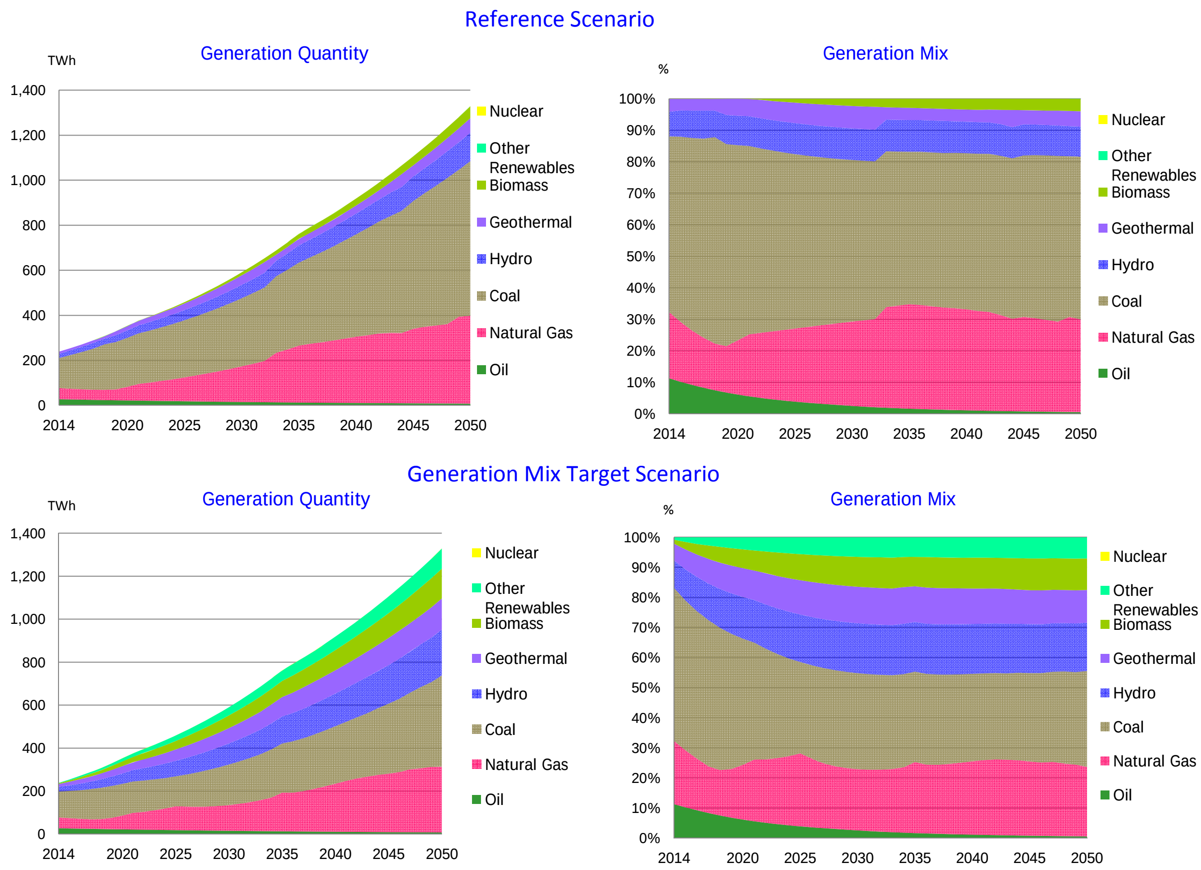


Figure 5.2.6 Power Generation Mix from 2014 to 2050 (Energy Mix)

The target energy mix for 2025 is set in this policy as follows:

- Oil: 23%;
- Gas: 22%;
- Coal: 32%;
- Renewables: 23%

Since the target is set on the national primary energy mix, the target power generation mix is set following this assumption as below:

- Oil: No new installation;
- Gas: <25.8% for 2025;

- Coal: <32% for 2025;
- Renewables: >38%

It is assumed that the power generation mix through 2050 will be maintained same as the structure prevailing in 2025.

Under the Energy Mix scenario, share of oil power generation is the same with that under the Reference scenario. Shares of the coal and natural gas in 2030 are 31.9% and 20.4%, respectively, and are 31.9% and 23.1%, respectively, in 2050. Because of the constraints on coal and natural gas power generation, renewable energies including hydro power are expected to play a significant role in power supply. The share of power generation from renewable energies including hydro power is expected to be 45.1% in 2030 and 44.5% in 2050. However, physical feasibility of this scenario must be examined.

Table 5.2.4 Power Generation Mix in 2025

	Generation (GWh)	Share (%)
Oil	17,926	3.9%
Natural Gas	111,098	24.2%
Coal	139,524	30.4%
Hydro	72,457	15.8%
Geothermal	52,355	11.4%
Biomass	39,716	8.7%
Other Renewables	25,804	5.6%
Nuclear	0	0.0%
Total	458,880	100.0%

Under this scenario, through 2050 the cumulative generation cost (including fuel cost) is estimated to be 3,145 billion US dollars, higher than that under the Reference scenario. The cumulative revenue from electricity tariff collection is 2,075 billion US dollars, which means until 2050 there will be 1,070 billion US dollars of deficit. Cumulative GHG emissions from new power generation will be less than that under the Reference scenario, 1,723million C-tons comparing with 2,973 million C-tons under the Reference scenario.

5.2.7 GHG Reduction Scenario

Under the GHG Reduction scenario, a constraint for GHG emission was imposed to achieve the government's emissions reduction target, which was 26% of GHG emissions by 2020 compared to the Reference scenario. In this scenario, it was assumed that the same constraint (26% reduction compared to the Reference scenario) is also applied beyond 2020 through to 2050.

Under the same assumption for oil, the share of oil power is same in this scenario as in the Reference scenario. To achieve the GHG reduction target, most of the coal power generation has to be switched to natural gas or renewable energies. As a result, bulk of the power generation comes from natural gas power, which accounts for 47.5% in 2030 and further goes up to 60.4% in 2050. On the other hand, the share of coal power generation is expected to be 20.7% in 2030 and further down to 14.6% in 2050. A 29.2% of the electricity demand in 2030 and a 24.4% in 2050 is expected to be met by renewable energies including hydro power.

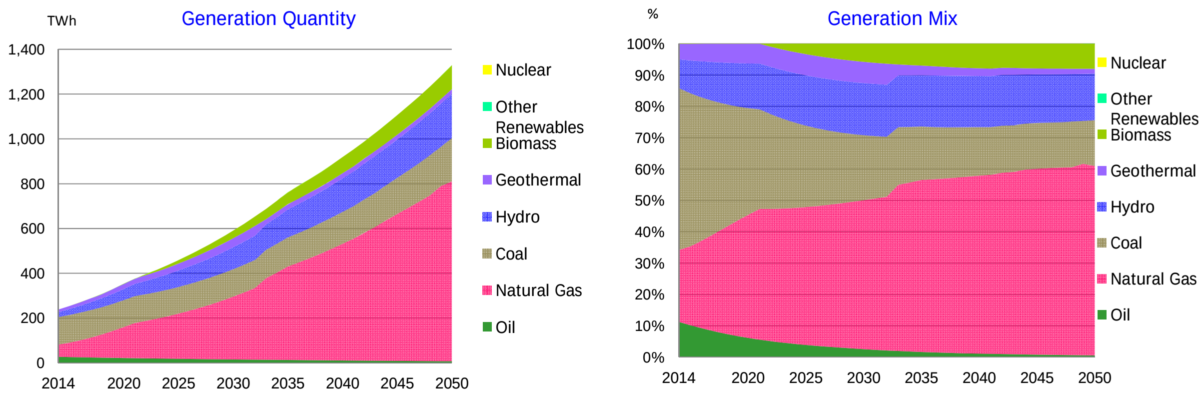


Figure 5.2.7 Power Generation Mix from 2014 to 2050 (GHG Reduction)

Under this scenario, through 2050 the cumulative generation cost (including fuel cost) is estimated to be 3,303 billion US dollars, the highest among all the scenarios. The cumulative revenue from electricity tariff collection is 2,075 billion US dollars, which means until 2050 there will be 1,228 billion US dollars of deficit. The amount of cumulative GHG emissions from the new power generation fleet is smallest among all the scenarios, 1,666 million C-tons till 2050.

5.2.8 Supply Side Efficiency

One way to reduce CO_2 emissions from power generation is to use power generation technologies with higher thermal efficiency. Coal or natural gas will be converted to electricity more efficiently in power plant with higher thermal efficiencies, which means with the same electricity output, less fuel is consumed. This study examined how the supply side efficiency, especially for coal power generation and natural gas power generation, would impact the generation cost, CO_2 emissions, and fossil fuel consumption. The technology configurations for coal and natural gas power generations set in the study are shown in the following table.

Technologies with higher efficiencies tend to have higher capital cost. However, since using technologies with higher efficiencies will reduce fuel consumption, thus will cut fuel cost. Different coal and natural gas technologies are applied to the Reference scenario. The total cumulative generation cost under different efficiency conditions are shown in the following figure. Built on the technology assumptions and the fuel cost assumptions, coal power generation with the medium efficiency is the most cost effective, while for natural gas power generation using the technology with the highest efficiency will lead to the lowest generation cost.

Table 5.2.5 Configurations of Coal and Nature Gas Power Generation Technologies with Different Efficiencies.

	Capacity (MW)	Life Time	Max Operating hr/yr	Min Operating hr/yr	Capacity Factor (Max)	Thermal Efficiency	Total CAPEX ($/kW)	Increasing /Decreasing of CAPEX	Total non-fuel OPEX ($/kWh)	CO2 Emission Factor (ton/toe)	NOX Emission Factor (ton/toe)	PM Emission Factor (ton/toe)
Coal (Low Efficiency)	500	35	7000	3000	80%	35%	1441	100%	0.006	1.04	0.01256	0.001675
Coal (Medium Efficiency)	1000	35	7000	3000	80%	40%	1590	100%	0.006	1.04	0.01256	0.001675
Coal (High Efficiency)	1000	35	7000	3000	80%	45%	1892	100%	0.006	1.04	0.01256	0.001675
Natural Gas (Low Efficiency)	300	25	7000	1000	80%	45%	718	100%	0.0065	0.58	0.011723	0.000209
Natural Gas (Medium Efficiency)	700	25	7000	1000	80%	50%	847	100%	0.0065	0.58	0.011723	0.000209
Natural Gas (High Efficiency)	1000	25	7000	1000	80%	60%	1164	100%	0.0065	0.58	0.011723	0.000209

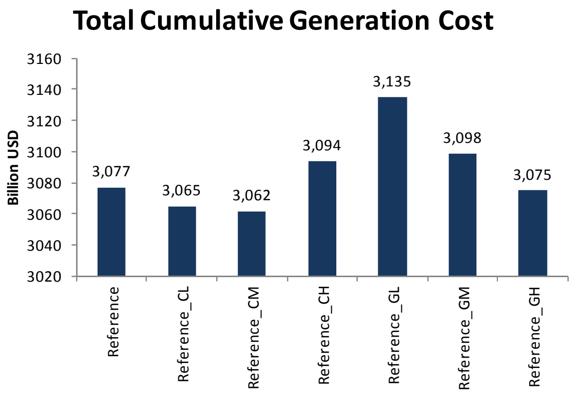


Figure 5.2.8 Total Cumulative Generation Cost under Different Efficiency Cases for the Reference Scenario

- Reference CL: for coal power generation only apply low efficiency technology, while others stay the same with the Reference scenario
- Reference CM: for coal power generation only apply medium efficiency technology, while others stay the same with the Reference scenario
- Reference CH: for coal power generation only apply high efficiency technology, while others stay the same with the Reference scenario
- Reference GL: for natural gas power generation only apply low efficiency technology, while others stay the same with the Reference scenario
- Reference GM: for natural gas power generation only apply medium efficiency technology, while others stay the same with the Reference scenario
- Reference GH: for coal power generation only apply high efficiency technology, while others stay the same with the Reference scenario

5.2.9 Supply side efficiency and CO_2 emissions

Simulations for 3 supply side efficiency cases (low, medium, high) were run for the GHG Emissions Reduction scenario. In the low efficiency case, low efficiency technologies are applied for both coal power generation and natural gas power generation, while in the medium efficiency case and the high efficiency case, the medium efficiency technologies and high efficiency technologies are applied, accordingly. Some of the results are shown in the following figures. Using technologies with the highest efficiency will result in the lowest CO_2 emissions. Although the total generation cost is not the lowest, the high efficiency case is the one with the lowest marginal cost for CO_2 emissions reduction (the cost for reducing a ton of CO_2 in carbon equivalent).

As compared in Table 5.2.6, among three cases examined, it looks most beneficial to adopt best efficiency technologies in terms of economics as well as reduction of GHG emissions.

Table 5.2.6 GHG Reduction plus Energy Efficiency

Scenarios		Reference	GHG Reduction	GHG Reduction Low Efficiency	GHG Reduction Middle Efficiency	GHG Reduction High Efficiency
Amount till 2050						
Total Cost	bil. US$	3,077	3,303	3,451	3,375	3,310
Total Revenue	bil. US$	2,075	2,075	2,075	2,075	2,075
Profit	bil. US$	-1,003	-1,228	-1,377	-1,301	-1,235
Profit Mark-up Ratio	%	67.4%	62.8%	60.1%	61.5%	62.7%
Subsidies incuding FITs	bil. US$	0	0	0	0	0
Gov't Total Net Inflow	bil. US$	-1,003	-1,228	-1,377	-1,301	-1,235
Tariff & Cost						
Electricity Tariff (2030)	¢ /kWh	8.14	8.14	8.14	8.14	8.14
Electricity Tariff (2050)	¢ /kWh	8.30	8.30	8.30	8.30	8.30
Unit Cost (2030)	¢ /kWh	12.21	12.78	13.21	12.96	12.82
Unit Cost (2050)	¢ /kWh	12.25	13.43	14.61	14.09	13.45
Electricity Demand (2050)	TWh	1,322	1,322	1,322	1,322	1,322
Additional Electricity Generation	TWh	1,272	1,272	1,272	1,272	1,272
Additional Fossil Fuel Consumption	Mil.toe	3,262	2,404	2,792	2,562	2,339
Coal	Mil.toe	2,351	590	678	593	527
Oil	Mil.toe	0	0	0	0	0
Natural Gas	Mil.toe	911	1,814	2,114	1,969	1,812
CO_2 Emissions	Mil.t-c	2,973	1,666	1,931	1,759	1,599
Fossil-Fuel Intensity	kg/kWh	2.56	1.89	2.20	2.01	1.84
Generation Mix (2030)						
Coal	%	51.2%	20.7%	20.7%	20.7%	20.7%
Oil	%	2.5%	2.5%	2.5%	2.5%	2.5%
Natural Gas	%	26.8%	47.5%	42.4%	43.7%	47.5%
Hydro	%	10.0%	16.6%	16.6%	16.6%	16.6%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	7.1%	6.8%	6.8%	6.8%	6.8%
Biomass	%	2.3%	5.8%	10.9%	9.6%	5.8%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%
Generation Mix (2050)						
Coal	%	51.7%	14.6%	14.6%	14.6%	14.6%
Oil	%	0.5%	0.5%	0.5%	0.5%	0.5%
Natural Gas	%	29.4%	60.4%	57.0%	57.8%	60.4%
Hydro	%	9.5%	14.9%	14.9%	14.9%	14.9%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	4.9%	1.5%	2.7%	2.5%	1.5%
Biomass	%	4.0%	8.0%	10.3%	9.7%	8.0%
Other NRE	%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%

When GHG emissions reduction is aimed with most advanced technologies, fossil fuel consumption will be reduced 923 million toe during the projection period, or 28.3% and GHG emissions 1,374 million C-tons or 46.2%. Coal consumption will be switched to natural gas significantly. If the future natural gas price becomes more competitive than assumed in this study, or much higher efficiencies are achieved via technology advance, this scenario may become much more attractive in the future. In this context, it is necessary to carefully watch tendencies in the international fuel market and technology progress.

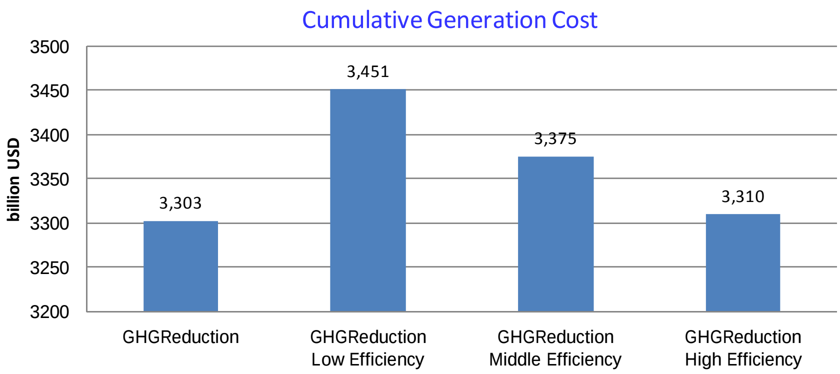


Figure 5.2.9 Total Cumulative Generation Cost under different efficiency cases for the GHG Reduction scenario

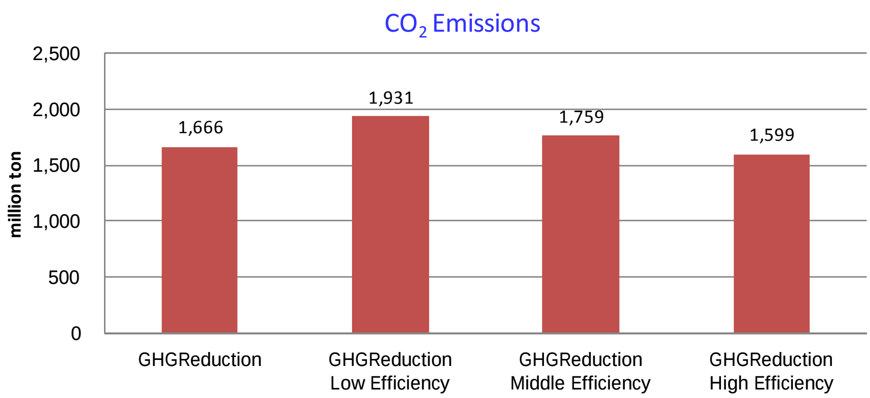


Figure 5.2.10 CO_2 Emissions under different efficiency cases for the GHG Reduction scenario

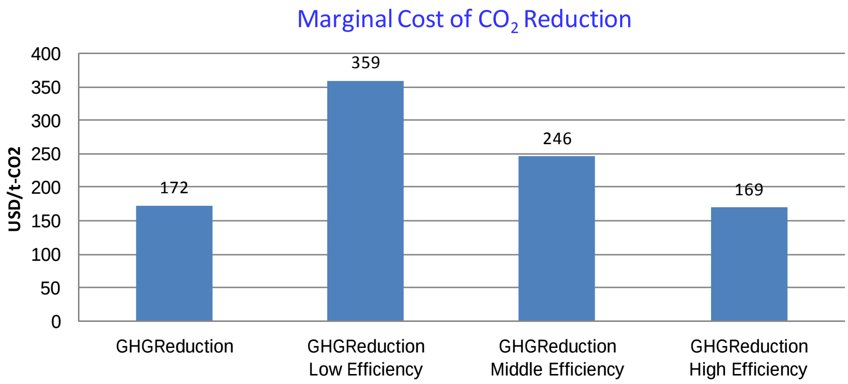


Figure 5.2.11 Marginal Cost of CO_2 Emission Reduction under different efficiency cases for the GHG Reduction scenario

5.3 Philippines

Table 5.3.1 shows a summary of scenarios run for the Philippines; Least Cost scenario, Reference scenario, Generation Target scenario, Feed-in Tariff scenario, High Efficiency scenario, and Electricity Tariff IRR5% scenario.

Accumulated total cost means the sum of the generation and transmission & distribution costs from 2014 to 2050. Accumulated total revenue means the sum of the electricity sales from 2014 to 2050. Thus, the balance of the total cost and the total revenue shows profit and loss for power business. If National Power Company does not have a profit, government or someone shall cover its loss. All scenarios in the Philippines yield a great amount of profits because the average electricity tariff at present in the Philippines is hovering around US$0.21/kWh in the highest level in Asia. Current tariff rate is higher than the cost for generation, transmission, and distribution in 2050 that is calculated by the model. In case of the Philippines, calculated unit cost of electricity in 2050 is between US cent 7.0/kWh and US cent 10.6/kWh as shown in Table 5.3.1.

Details of each scenario are explained in the following sections.

Table 5.3.1 Summary of Scenarios for the Philippines

		Reference (BAU)	Least Cost	Generation Target	Feed-in Tariff	High Efficiency	Electricity Tariff IRR5%
Amount till 2050							
Total Cost	bil. US$	579	432	581	579	560	629
Total Revenue	bil. US$	1,257	924	1,333	1,257	1,210	609
Profit	bil. US$	678	493	752	678	650	-20
Profit Mark-up Ratio	%	217	214	230	217	216	97
Subsidies incuding FITs	bil. US$	0.0	0.0	0.0	0.0	0.0	0.0
Gov't Total Net Inflow	bil. US$	678	493	752	678	650	-20
Tariff & Cost							
Electricity Tariff (2030)	¢/kWh	21.4	13.5	22.9	21.4	19.8	8.5
Electricity Tariff (2050)	¢/kWh	21.4	15.6	22.9	21.4	20.7	9.7
Unit Cost (2030)	¢/kWh	11.5	7.3	12.5	11.5	10.7	10.8
Unit Cost (2050)	¢/kWh	9.9	7.0	10.0	9.9	9.5	9.5
Electricity Demand (2050)	TWh	425	439	422	425	426	464
Cumulative Additional Electricity Generation	TWh	5,871	6,172	5,819	5,871	5,910	6,595
Cumulative Additional Fossil Fuel Consumption	Mil.toe	1,221	1,113	1,184	1,221	982	1,402
Coal	Mil.toe	888	1,113	981	888	734	1,078
Oil	Mil.toe	0	0	0	0	15	7
Natural Gas	Mil.toe	333	0	203	333	233	316
CO_2 Emissions	Mil.t-c	1,117	1,158	1,138	1,117	910	1,310
Fossil-Fuel Intensity	kg/kWh	0.208	0.180	0.203	0.208	0.166	0.213
Generation Mix (2030)							
Coal	%	45.8%	61.1%	50.9%	45.8%	49.1%	51.7%
Oil	%	2.8%	2.7%	2.9%	2.8%	2.8%	3.1%
Natural Gas	%	41.8%	7.4%	29.2%	41.8%	34.8%	36.3%
Hydro	%	5.6%	24.9%	7.0%	5.6%	9.3%	5.3%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	4.0%	3.8%	8.0%	4.0%	3.9%	3.6%
Biomass	%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%
Other NRE	%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Generation Mix (2050)							
Coal	%	69.9%	77.9%	76.4%	69.9%	72.3%	74.8%
Oil	%	0.5%	0.5%	0.5%	0.5%	2.3%	0.7%
Natural Gas	%	26.3%	1.4%	13.8%	26.3%	19.6%	21.5%
Hydro	%	2.5%	19.5%	2.8%	2.5%	5.1%	2.4%
Nuclear	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	%	0.7%	0.7%	2.8%	0.7%	0.7%	0.6%
Biomass	%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%
Other NRE	%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

5.3.1 Reference Scenario (BAU)

In this scenario, amount of power generation in 2050 in the Philippines is 425TWh, which compares to one-third of the current power generation in Japan. Other major assumptions are;

a. Power generation from gas-fired power plants shall be kept at the current level in the generation mix via domestic and imported natural gas.

b. Power generation from hydro-power and geothermal plants should not exceed the present resource potential.

c. Power generation by nuclear is assumed to start from 2030 as a given condition.

It is also assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.3.1 shows the generation mix of the Reference scenario arrived at least cost under the above constraints. In 2050, most of the power generation will be supplied by coal-fired power plant (69.9%), followed by gas-fired power (26.3%), hydro power (2,5%), geothermal power (0.7%) and oil-fired power (0.5%).

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$579 billion and US$1,257 billion respectively, with a surplus of US$678 billion.

The accumulated CO_2 emissions till 2050 reach 1,117 million C-tons, greatly increasing from 6.4 million C-tons in 2020 to 83.6 million C-tons in 2050, reflecting the dominant increase of coal-thermal plants. How to control CO_2 emissions and generation economics will be one of the key issues for setting the long term energy policy of the Philippines.

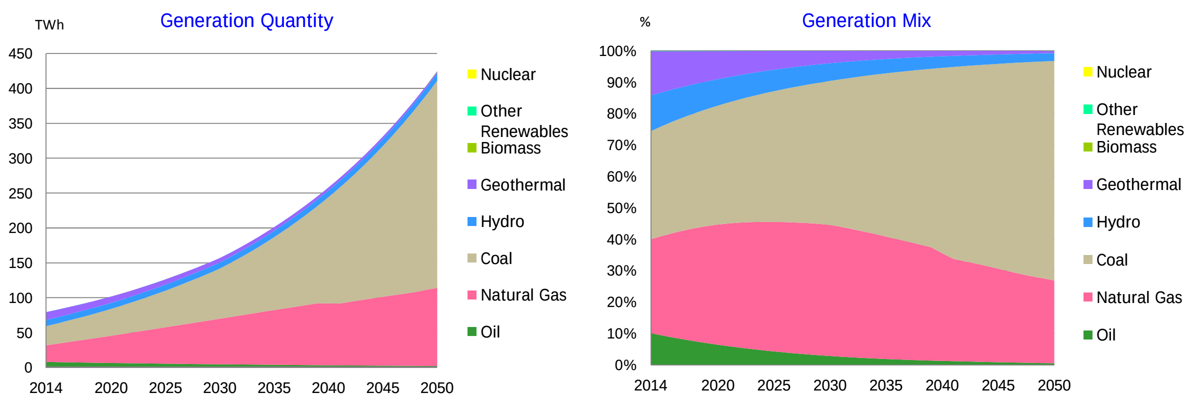


Figure 5.3.1 Reference Scenario: Philippines

5.3.2 Least Cost Scenario

In this scenario, amount of power generation in 2050 in the Philippines is same as the Reference scenario. Other major assumptions are;

a. Power generation from gas-fired power plants shall not be constrained to the current level.

b. Power generation from hydro-power and geothermal plants should not exceed the present resource potential.

c. Power generation by nuclear is assumed to start from 2030 as a given condition.

It is also assumed that the existing power plant capacity will be gradually phased out to a half in

20 years from 2014.

Figure 5.3.2 shows the generation mix of the Least Cost Scenario arrived at least cost under the above constraints. In 2050, most of the power generation will be made by coal-fired power plant (77.9%), followed by hydro power (19.5%), gas-fired power (1.4%), geothermal power (0.7%) and oil-fired power (0.5%).

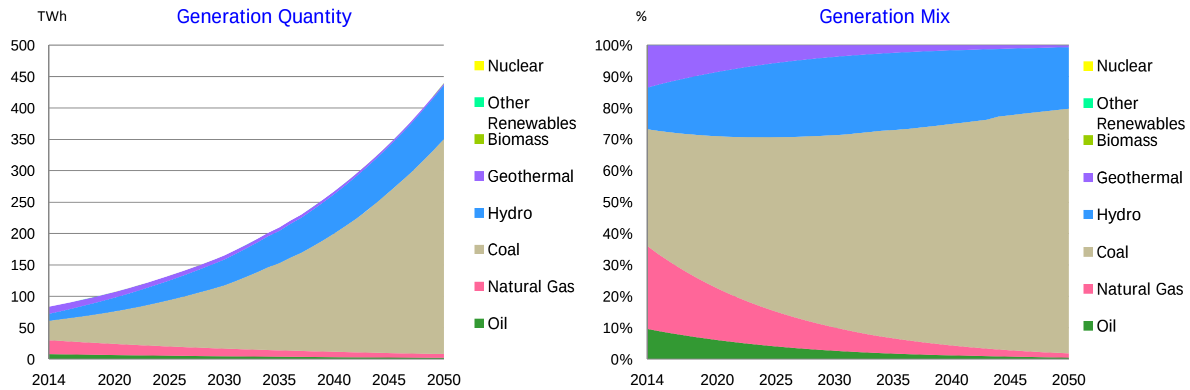


Figure 5.3.2 Least Cost Scenario: Philippines

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$432 billion and US$924 billion respectively, with a surplus of US$493 billion. The accumulated CO_2 emission till 2050 reaches 1,158 million C-tons, greatly increasing from 7.8 million C-tons in 2020 to 81.3 million C-tons in 2050, reflecting the dominant increase of coal-thermal plants.

5.3.3 Generation Target Scenario

In this scenario, amount of power generation in 2050 is same as derived under the Reference scenario. Constraints are given on the generation mix targets; that is, 7.0% for hydro, 8.0% for geothermal, 1% for biomass and 1.0% for solar in 2030. Other constraints are same as applied for the Reference scenario.

It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.3.3 shows the generation mix at least cost under above constraints. In 2050, most of the power generation will come from coal-fired power (76.4%), followed by gas-fired power (13.8%), geothermal power (2.8%), hydro power (2.8%), biomass power (1.9%), solar power (1.8%), and oil-fired power (0.5%).

The accumulated total cost and accumulated total revenue till 2050 are US$581 billion and US$1,333 billion respectively, with a surplus of US$752 billion. The accumulated CO_2 emission till 2050 further increases by 2% from the Reference scenario to reach 1,138 million C-tons.

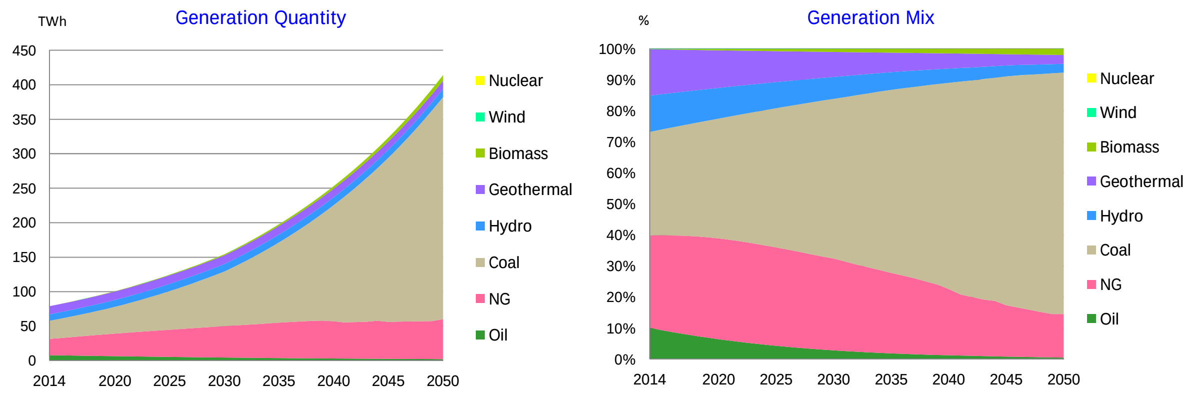


Figure 5.3.3 Conditioned Generation Mix Scenario: Philippines

5.3.4 Feed-in Tariff Scenario

In this scenario, feed-in tariffs are set at US$0.19/kWh for wind, US$0.22/kWh for solar, and US$0.15/kWh for biomass. Other assumptions are;

a. Power demand in 2050 is 430TWh same as the Reference scenario.

b. Other constraints are same as the Reference scenario.

It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.3.4 shows the generation mix at least cost under the above conditions. In 2050, power generation comprises coal-fired power (69.9%), followed by gas-fired power (26.3%), hydro power (2.5%), geothermal power (0.7%), and oil-fired power (0.5%). This generation mix is same as Reference scenario because renewable energies are not introduced even feed-in tariff is given to renewable energies.

The accumulated total cost and accumulated total revenue till 2050 are US$579 billion and US$1,257 billion respectively, with a surplus of US$678 billion. The accumulated CO_2 emission till 2050 reaches 1,117 million C-tons same as the Reference scenario.

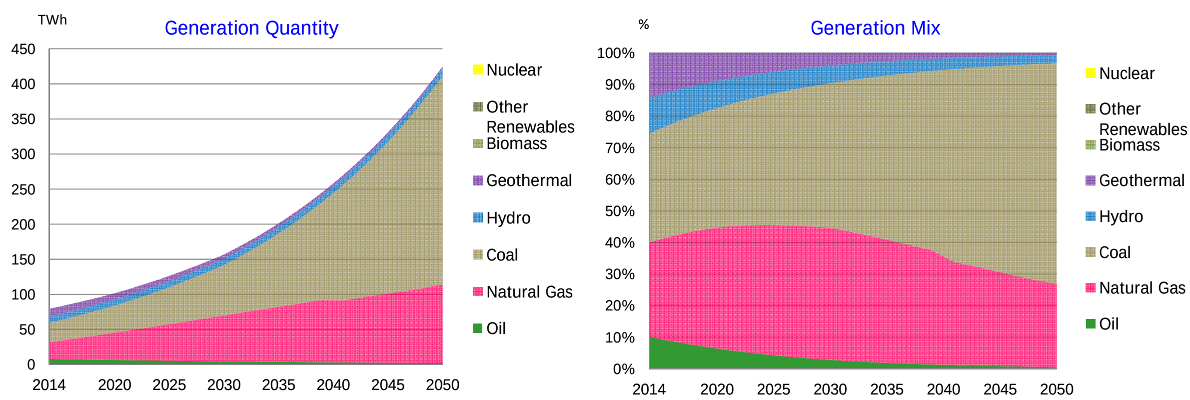


Figure 5.3.4 FIT Scenario: Philippines

5.3.5 Thermal Efficiency Scenario

In this scenario, amount of power generation in 2050 is same as derived under the Reference scenario. Constraints are given on the thermal efficiency targets; that is, 60% for gas-fired power plants and 45% for coal-fired power plants. Other constraints are same as applied for the Reference scenario. It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.

Figure 5.3.5 shows the generation mix of the Thermal Efficiency scenario arrived at least cost under the above constraints. In 2050, most of the power generation will be supplied by coal-fired power plant (72.3%), followed by gas-fired power (19.6%), hydro power (5.1%), oil-fired power (2.3%), and geothermal power (0.7%).

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$560 billion and US$1,210 billion respectively, with a surplus of US$650 billion. Under the Reference scenario, less effective cheaper plants are selected to a considerable extent. As compared in Figure 5.3.5, if we condition that only most efficient plants (60% efficiency CCGT and 45% efficiency USC coal thermal) can be chosen, the total accumulated cost be lowered by 3.5% from the Reference scenario projection. However, because of the higher financial cost, they are not chosen under the Reference scenario.

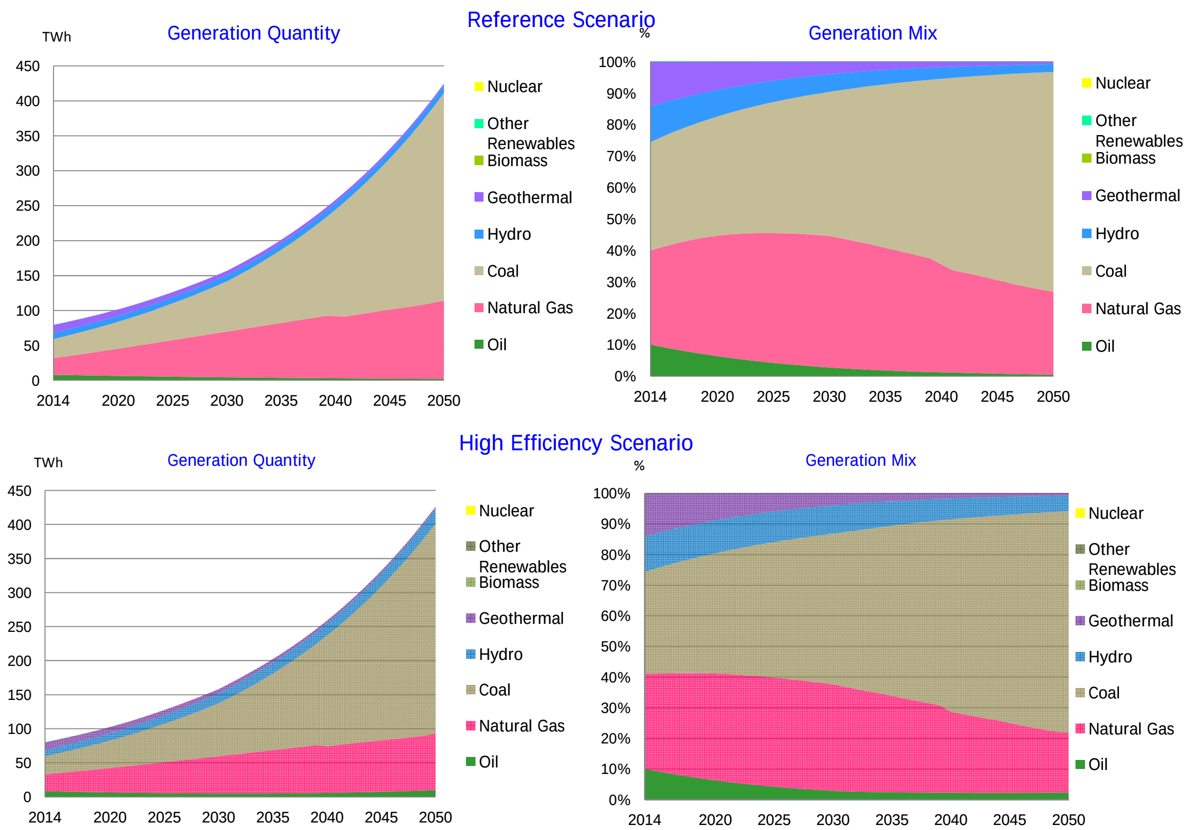
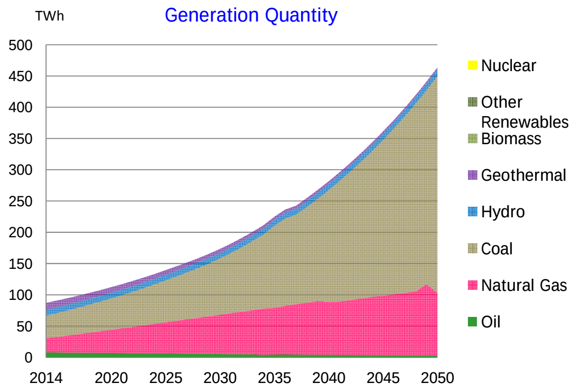


Figure 5.3.5 Thermal Efficiency Scenario: Philippines

Compared with the Reference scenario projection, the cumulative additional amount of fossil fuel consumption will be reduced by 19.5% and the CO_2 emissions by 18.5%. Controlling import dependence of fossil fuels as well as CO_2 emissions, high efficiency thermal power plants will be the most effective measure in all scenarios.

5.3.6 Electricity Tariff IRR 5% Scenario

In this scenario, amount of power generation in 2050 is same as derived under the Reference scenario. Constraints are given on the electricity tariff to meet 5% of IRR. Other constraints are same as applied for the Reference scenario. It is assumed that the existing power plant capacity will be gradually phased out to a half in 20 years from 2014.



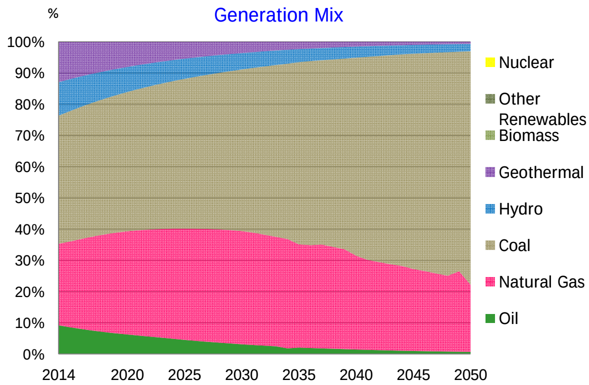


Figure 5.3.6 Electricity Tariff IRR 5% Scenario: Philippines

Figure 5.3.6 shows the generation mix of the Electricity Tariff IRR 5% scenario arrived at least cost under the above constraints. In 2050, most of the power generation will be supplied by coal-fired power plant (74.8%), followed by gas-fired power (21.5%), hydro power (2.4%), oil-fired power (0.7%), and geothermal power (0.6%).

The accumulated total cost and accumulated total revenue during the projection period till 2050 will be US$629 billion and US$609 billion respectively, with a deficit of US$20 billion. But average electricity tariff in 2050 for end-user is UScents9.5/kWh. This is a half of the current electricity tariff. The accumulated CO_2 emission till 2050 reaches 1,310 million C-tons. Amount of CO_2 emission of this scenario is the highest in all scenarios.

5.4 ASEAN

5.4.1 General Assumptions

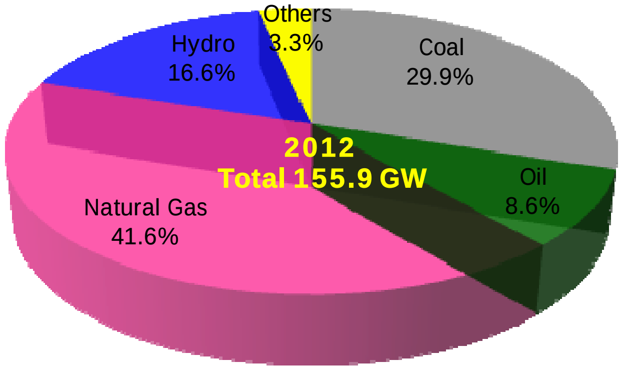
Outline of the present ASEAN electricity sector is as follows:

1) According to the statistics of the IEA and the United Nations, the final electricity demand of the

ASEAN 10 countries was 616 TWh in 2011, with industry account for 41.1%, business/commercial 27.7%, household 30.1% and others 1.1%.

2) According to the IEA statistics, the total power generation for the same year was 694TWh, with coal-thermal 216TWh (33%), natural gas-thermal 307TWh (46%), oil-thermal 71TWh (7%), hydro 73TWh (9%), geothermal 19TWh (4%), and others (mainly biomass) 8TWh (1%).

3) According to various national statistics and statements, the power generation capacity of the ASEAN10 countries in 2012 was 156GW, with coal-thermal accounting for 29.9%, natural gas-thermal 41.6%, oil-thermal 8.6%, hydro 16.6%, others (geothermal, biomass, wind , PV, etc.) 3.3%.



Source: National statistics and other information

Figure 5.4.1 Composition of Power Generation Capacity of ASEAN (2012)

4) We also estimate from various data that electricity tariffs in 2012 for the whole ASEAN region were on average US Cents 10.5/kWh for industry sector, US Cents 11.3/kWh for business/commercial sector and US Cents 11.0/kWh for household.

We estimate that the power generation requirement including plant own use and transmission/delivery losses will grow to 1778TWh in 2030 (average annual growth rate 4.9% between 2011 and 2030), and to 3504 TWh in 2050 (3.5% between 2030 and 2050), which is slightly higher than the projection made in the IEEJ's Asia/World Energy Outlook 2013 taking account of the recent development.

Table 5.4.1 Power Mix in Reference Scenario

	Electricity Demand					Composition		
	2014	2030	2050	14-->30	30-->50	2014	2030	2050
	TWh	TWh	TWh	%	%	%	%	%
Oil	34.8	56.7	9.0	163	16	4.1	3.2	0.3
Natural Gas	364.4	788.1	1302.2	216	165	43.4	44.3	37.2
Coal	203.3	657.1	1617.1	323	246	24.2	37.0	46.1
Hydro	232.4	165.3	400.2	71	242	27.7	9.3	11.4
Geothermal	2.2	36.1	42.5	1,669	118	0.3	2.0	1.2
Biomass	1.6	20.1	26.4	1,235	131	0.2	1.1	0.8
Other Renewables	0.8	14.4	30.4	1,700	212	0.1	0.8	0.9
Nuclear	0.0	40.0	76.7	**	192	0.0	2.3	2.2
Total	839.6	1777.9	3504.4	212	197	100.0	100.0	100.0
Fossil Fuels	602.6	1502.0	2928.3	249	195	71.8	84.5	83.6

With the above backdrop and general assumption on plant costs and fuel prices explained in Chapter 4, we have run the Reference Scenario. Additional specific assumptions are made as follows:

1) Because of resource and time constraints, the maximum hydro capacity shall be 165 TWh per annum for 2030 and 400 TWh for 2050.
2) The maximum geothermal capacity shall be 74 TWh for 2030 and 156 TWh for 2050.
3) The maximum nuclear capacity shall be 7 GW or 40 TWh for 2030 and 13GW or 77 TWh for 2050, which may be constructed in Vietnam, Indonesia and the Philippines.

The resultant power mix for the Reference Scenario is summarized in Table 5.4.1 and Figure 5.4.2.

Under the Reference scenario, fossil fuels will continue to dominate in the ASEAN power mix. Fossil fuel ratio will rather increase from the present 70% plus to over 80% mainly because large scale hydro power potential will become scarce. Other renewable energy will significantly increase, though their share in the power mix remains relatively small even in 2050. To utilize fossil fuel efficiently, advanced technology plants, such as A-USC and CCGT, will be proactively introduced. Other important indicators such as unit cost and CO_2 emissions are also summarized in Table 5.4.2.

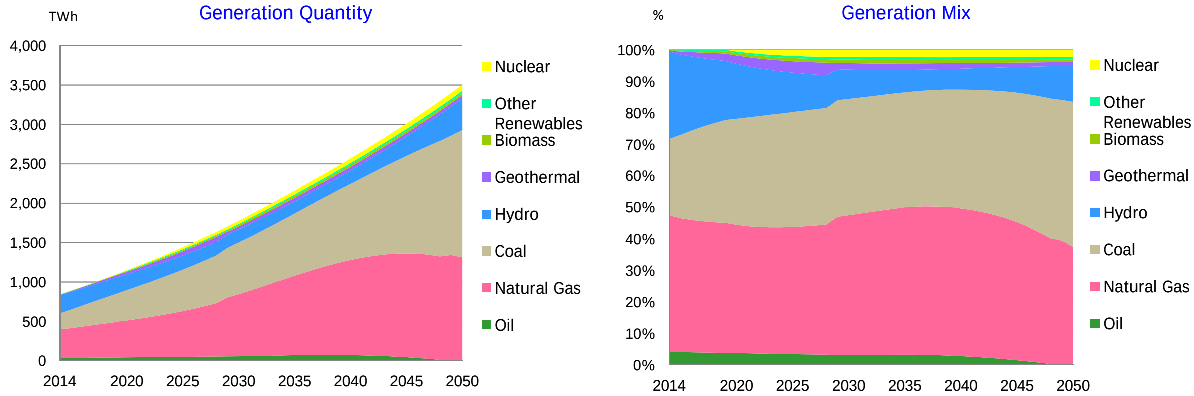


Figure 5.4.2 Generation Power Mix: Reference Scenario

Table 5.4.2 Major Indicators: Reference Scenario

Item	Unit	Value
Total Cost	bil. US$	6375.6
Fuel Cost	bil. US$	145.9
Subsidies incuding FITs	bil. US$	0.0
Gov't Total Net Inflow	bil. US$	0.0
Tariff & Cost		
Electricity Tariff	¢/kWh	9.58
Unit Cost	¢/kWh	10.98
Electricity Demand	TWh	3504.41
CO2 Emissions	Mil.t-c	7,762
Fossil-Fuel Intensity	kg/kWh	0.133

5.4.2 Generation Efficiency Improvement Scenario

Under the Efficiency Improvement Scenario, it is assumed that all high efficiency thermal plants introduced from 2014 onward should be presently available highest efficiency models; such as natural gas thermal plants at 60% fuel efficiency, coal thermal plants at 45% and oil thermal (diesel) at 36%. Simulation naturally reflects the assumptions and investment amount increases for latest technology models while decreases in case of adopting relatively inefficient old models such as coal thermal at 35%, natural gas thermal at 45% and oil thermal at 30%. The required investment amount for the high efficiency scenario will increase from $1,273 billion for the case adopting low efficiency plants to $ 1,740 billion by $ 467 billion or 37%. On the other hand, reflecting reduced fossil fuel consumption, the overall generation cost including fuel expense will decrease by $ 611 billion. The cumulative CO_2 emissions will be least at 6,551 million tons-C, compared with 7,762 million tons-C in the Reference Scenario and 8,565 million tons-C in the Low Efficiency Scenario.

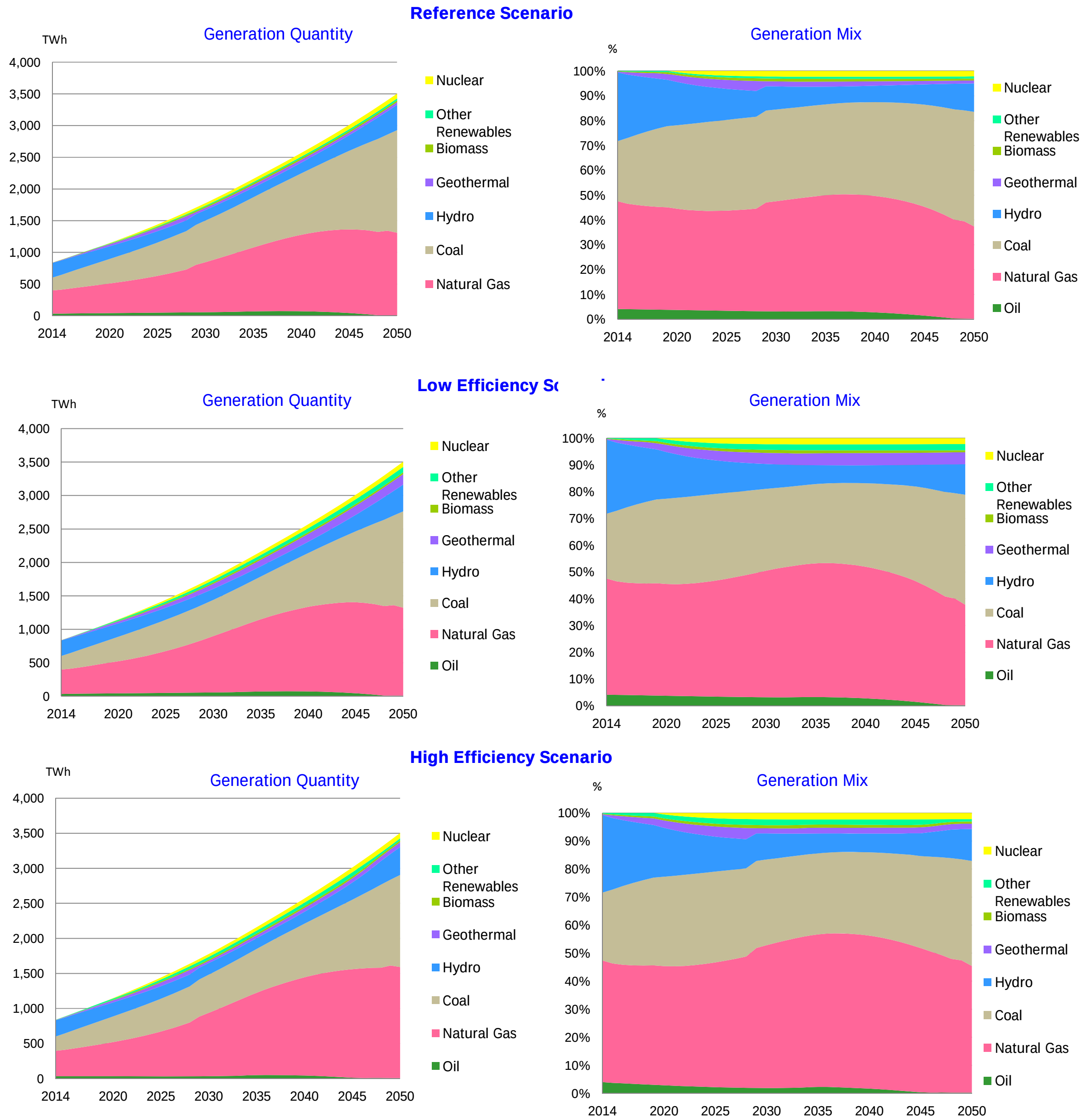


Figure 5.4.3 Comparison of Generation Efficiencies

As illustrated here, high efficiency natural gas thermal plants have very strong competitive edge against coal thermal and geothermal despite relative higher fuel price, and thus will be increasingly selected in the power mix. It is important to consider the cumulative total cost through the whole plant life rather than sticking to reduction of the initial investment amount. In order to make such selection possible, it is important to provide long term finance/credit for electric power investors. These simulation results are compared in Table 5.4.3.

Table 5.4.3 Improving Generation Efficiencies

Case		Reference	A-1	A-2
Policy set		Reference	High Efficiency	Low Efficiency
Amount till 2050				
Total Cost	bil. US$	6,376	6,504	7,115
Fuel Cost	bil.toe	146	153	181
Tariff & Cost				
Electricity Tariff (2030)	¢/kWh	12.1	12.4	13.5
Electricity Tariff (2050)	¢/kWh	9.6	9.9	10.6
Unit Cost (2030)	¢/kWh	11.9	12.1	13.2
Unit Cost (2050)	¢/kWh	11.0	11.2	12.2
Cummulative Electricity Generation	TWh	3,293	3,293	3,293
Cummulative Fossil Fuel Consumption	Mil.toe	9,106	8,200	10,531
Coal	Mil.toe	5,263	3,848	5,189
Oil	Mil.toe	284	119	330
Natural Gas	Mil.toe	3,559	4,233	5,011
CO_2 Emissions	Mil.t-c	7,762	6,551	8,565
Fossil-Fuel Intensity	kg/kWh	0.13	0.12	0.16
Generation Mix (2030)				
Coal	%	37.0%	30.5%	30.5%
Oil	%	3.2%	1.9%	3.2%
Natural Gas	%	44.3%	50.9%	47.3%
Hydro	%	9.3%	9.3%	9.3%
Nuclear	%	2.3%	2.3%	2.3%
Geothermal	%	2.0%	1.8%	4.2%
Biomass	%	1.1%	1.1%	1.1%
Other NRE	%	0.8%	2.1%	2.1%
Total	%	100%	100.0%	100.0%
Generation Mix (2050)				
Coal	%	46.1%	37.4%	41.1%
Oil	%	0.3%	0.3%	0.3%
Natural Gas	%	37.2%	45.2%	37.5%
Hydro	%	11.4%	11.4%	11.4%
Nuclear	%	2.2%	2.2%	2.2%
Geothermal	%	1.2%	1.9%	4.5%
Biomass	%	0.8%	0.8%	0.8%
Other NRE	%	0.9%	0.9%	2.3%
Total	%	100%	100.0%	100.0%

5.4.3 GHG Reduction Scenario

Reduction of GHG emissions will be implemented through energy efficiency and conservation, and fuel shift in the generation mix, in particular curbing coal thermal power generation. Introduction of renewable energies is another important measure, however, because of its high generation cost, it is deemed difficult that renewables would replace with fossil fuels and/or nuclear in a shorter period. Nuclear would be the most powerful measure to reduce GHG emissions.

However, due to the Fukushima Dai-ichi accident, it has become difficult to introduce a significant capacity of nuclear in ASEAN countries before 2030. Here, we compare the GHG Reduction Scenario and the Nuclear Promotion Scenario as shown in Table 5.4.4.

Table 5.4.4 GHG Reduction

Policy set		Reference	GHG Reduction	Nuclear Promote
Amount till 2050				
Total Cost	bil. US$	6,376	6,719	6,479
Fuel Cost	bil.toe	146	174	119
Electricity Cost				
Unit Cost (2030)	¢/kWh	11.9	12.5	12.0
Unit Cost (2050)	¢/kWh	11.0	11.6	11.2
Cummulative Electricity Generation	TWh	3,293	3,293	3,293
Cummulative Fossil Fuel Consumption	Mil.toe	9,106	8,421	8,307
Coal	Mil.toe	5,263	2,973	5,261
Oil	Mil.toe	284	284	284
Natural Gas	Mil.toe	3,559	5,164	2,762
CO_2 Emissions	Mil.t-c	7,762	6,312	7,298
Fossil-Fuel Intensity	kg/kWh	0.13	0.12	0.13
Generation Mix (2030)				
Coal	%	37.0%	22.9%	37.0%
Oil	%	3.2%	3.2%	3.2%
Natural Gas	%	44.3%	56.3%	37.8%
Hydro	%	9.3%	9.3%	9.3%
Nuclear	%	2.3%	2.3%	9.0%
Geothermal	%	2.0%	4.2%	1.8%
Biomass	%	1.1%	1.1%	1.1%
Other NRE	%	0.8%	0.8%	0.8%
Total	%	100%	100%	100%
Generation Mix (2050)				
Coal	%	46.1%	27.7%	46.0%
Oil	%	0.3%	0.3%	0.3%
Natural Gas	%	37.2%	55.6%	26.9%
Hydro	%	11.4%	11.4%	11.4%
Nuclear	%	2.2%	2.2%	12.9%
Geothermal	%	1.2%	1.2%	0.9%
Biomass	%	0.8%	0.8%	0.8%
Other NRE	%	0.9%	0.9%	0.9%
Total	%	100%	100.0%	100.0%

For the GHG Reduction Scenario, the target is assumed to reduce CO_2 emissions by more than 15% during the projection period from 7,762 million tons-C under the Reference Scenario, which inevitably reduces coal thermal plants. To achieve this target, it is necessary to reduce the share of coal thermal from 37.0% to 22.9% in 2030 and from 46.1% to 27.7% in 2050. At the expense of reducing coal thermal, natural gas thermal increases and pushes up the cumulative fuel cost by $ 343 billion. It would be quite controversial from the view point of sound socio-economic development if this huge amount could be fully transferred to consumers.

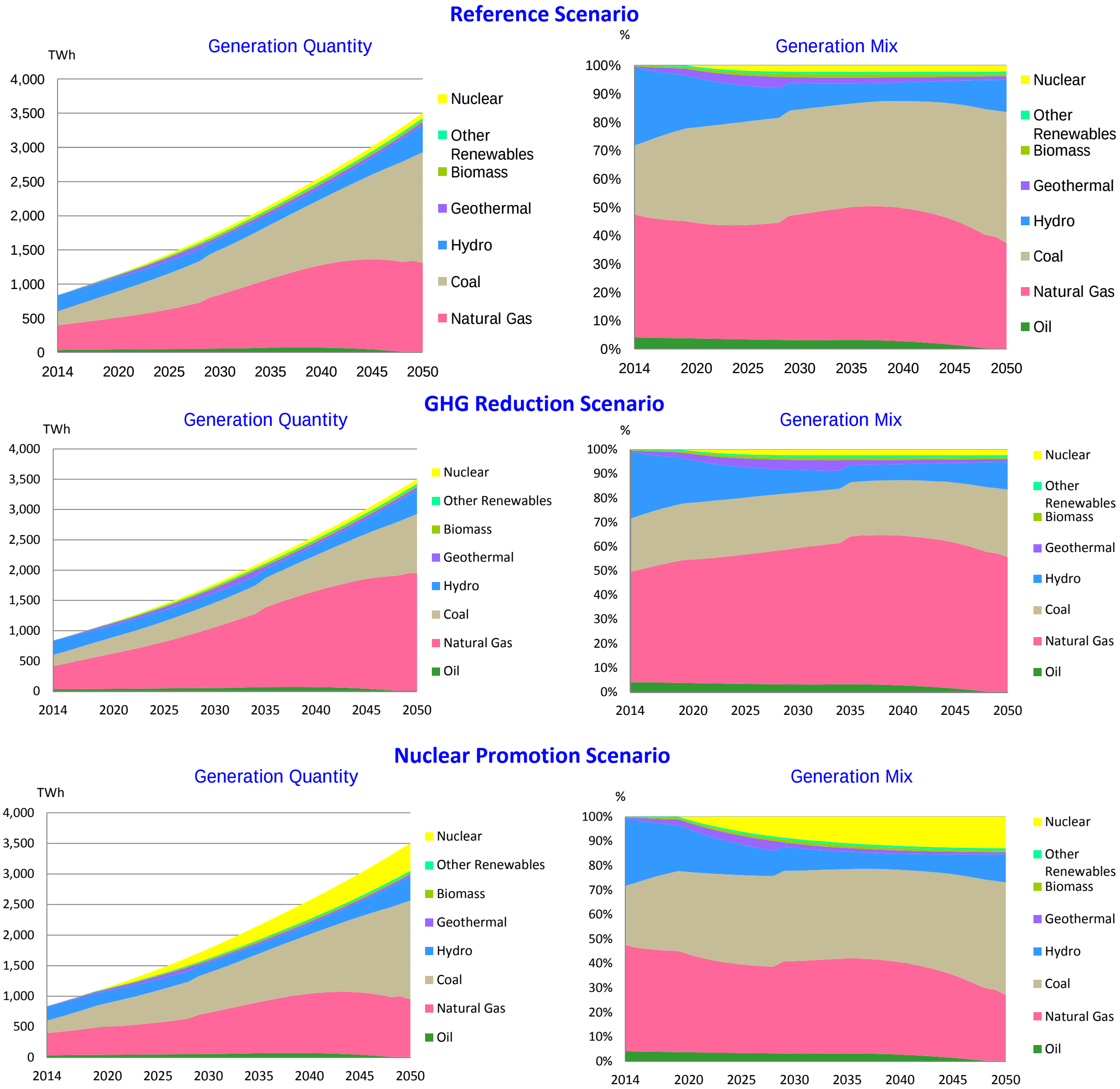


Figure 5.4.4 GHG Reduction and Nuclear promotion

Under the Nuclear Promotion Scenario, nuclear power generation should be proactively introduced in ASEAN countries in 2030 onward. Then, nuclear capacity in ASEAN may reach 28.6 GW in 2050 compared with 13.0 GW considered in the Reference Scenario. CO_2 emissions will be reduced more than 6% from the Reference Scenario, and the generation cost will be decreased significantly due to reduced coal thermal. The generation tariff will be slightly higher than the Reference Scenario, but cheaper than the GHG reduction scenario using coal thermal plants. Proactive introduction of nuclear will reduce import dependence of ASEAN, and thus be considered as an important measure to enhance energy security.

5.4.4 Renewables Promotion Scenario

Under the Renewable Promotion Scenario, renewable energies are deemed as the important future energy supply measure while their cost will gradually be reduced by technology progress and wider deployment. However, at present, it is necessary to provide subsidies to encourage introduction of renewable power generation. In this scenario, we calculated the amount of CO_2 reduction and necessary subsidies if we try to increase the share of wind and PV generation by 1% from the Reference Scenario.

Table 5.4.5 Renewable Energy Promotion

Policy set		Reference	Renewable Promote
Amount till 2050			
Total Cost	bil. US$	6,376	6,331
Fuel Cost	bil.toe	146	152
Subsidies incuding FITs	bil. US$	0	-142.9
Gov't Total Net Inflow	bil. US$	0	-142.9
Tariff & Cost			
Electricity Tariff (2030)	¢/kWh	12.1	12.0
Electricity Tariff (2050)	¢/kWh	9.6	9.6
Unit Cost (2030)	¢/kWh	11.9	12.1
Unit Cost (2050)	¢/kWh	11.0	11.1
CO_2 Emissions	Mil.t-c	7,762	7,104
Fossil-Fuel Intensity	kg/kWh	0.13	0.13
Generation Mix (2030)			
Coal	%	37.0%	31.4%
Oil	%	3.2%	2.6%
Natural Gas	%	44.3%	49.3%
Hydro	%	9.3%	9.3%
Nuclear	%	2.3%	2.3%
Geothermal	%	2.0%	2.0%
Biomass	%	1.1%	1.1%
Other NRE	%	0.8%	1.9%
Total	%	100%	100.0%
Generation Mix (2050)			
Coal	%	46.1%	40.2%
Oil	%	0.3%	0.3%
Natural Gas	%	37.2%	42.5%
Hydro	%	11.4%	10.9%
Nuclear	%	2.2%	2.2%
Geothermal	%	1.2%	1.2%
Biomass	%	0.8%	0.8%
Other NRE	%	0.9%	2.0%
Total	%	100%	100.0%

Under this scenario, the share of wind and PV combined in the power generation mix will be 1.9% in 2030 with power generation capacity at 15.5GW and annual generation amount at 34 TWh, and in 2050 the share will be 4.6% with power generation capacity of 32.7 GW and the generation amount at 71 TWh.

Under the wind and PV promotion scenario, the cumulative amount of subsidies will reach $ 143 billion by 2050. However, the total cumulative cost will be smaller than the Reference Scenario by \$45 billion. CO_2 emissions will be 7,762 million tons-C compared with 7,104 million tons-C for the Reference Scenario; a reduction of 658 million tons-C or 8.5% is significant.

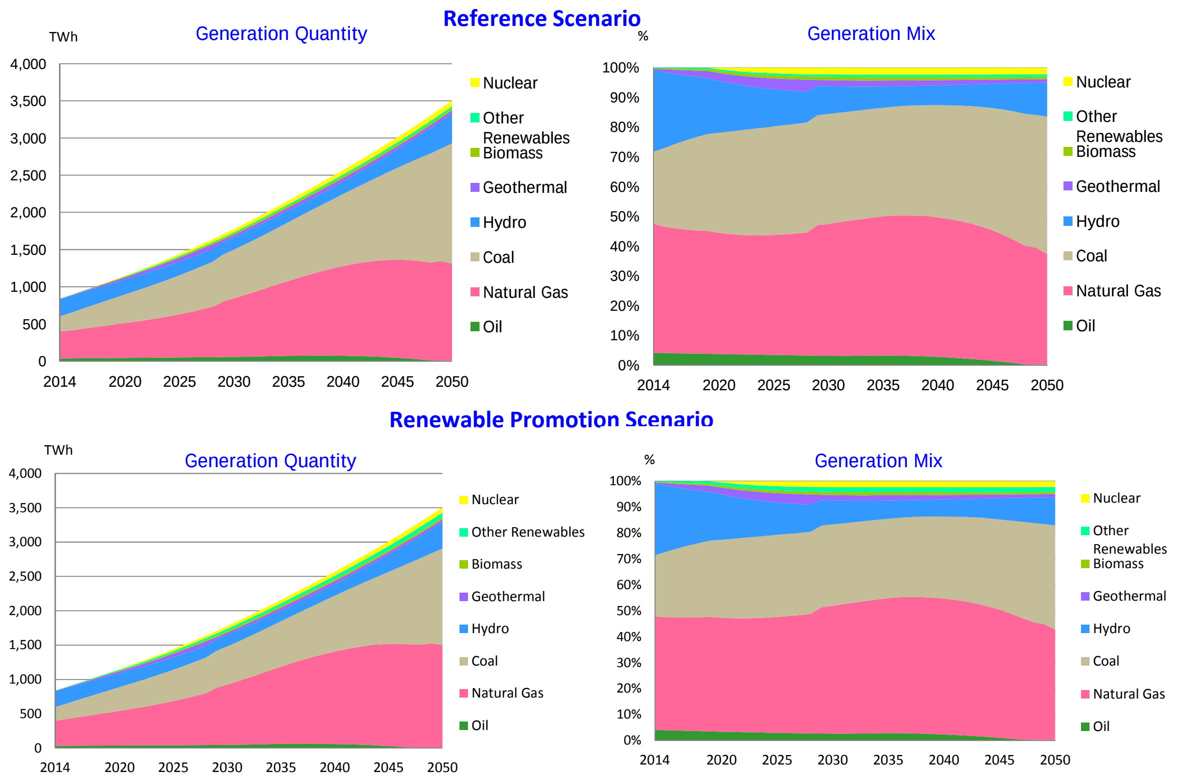


Figure 5.4.5 Renewable Promotion Scenario

On the other hand, the electricity tariff may become higher than in other scenarios reflecting higher equipment cost, and thus cast questions on affordability in lower income countries. Beyond 2030, however, electricity tariff is expected to decline with technology progress and large scale production, which will gradually improve affordability of renewables.

In order to proactively introduce wind and PV, various favorable conditions are required such as geographical location, climate and natural conditions, efficient grid management system as well as financial capacity of the state government to provide subsidies. Although the direction of the policy is desirable, it is not easy to realize a large scale utilization of renewables in a short period of time.

5.4.5 Advantage of ASEAN Grid Interconnection

The ASEAN grid interconnection will bring various advantages through integration of presently fragmented grids and markets into a huge ASEAN grid. It will significantly increase potential of utilizing highly efficient large scale plants and complimentary operation of them.

The economy of scale will reduce the overall cost and utilization of highly efficient plants can contribute to reduction of CO_2 emissions. We have run a comparison of low, medium and high efficiency scenarios through 2050 varying efficiencies of optional plants, as shown in Figure 5.4.6 below. These comparisons show that switching from the low efficiency scenario to the high efficiency scenario, the total cost and unit cost of power generation can be reduced about 8%, and CO_2 emissions far significantly by 23%. This calculation would not necessary mean that such reduction could be fully materialized in Thailand, Indonesia (Java), or Vietnam where large demand markets are already formed. However, advantages of interconnection will be particularly high for countries of fragmented and small grids like the cases of the Philippines, Cambodia, Myanmar and substantial areas of Indonesia.

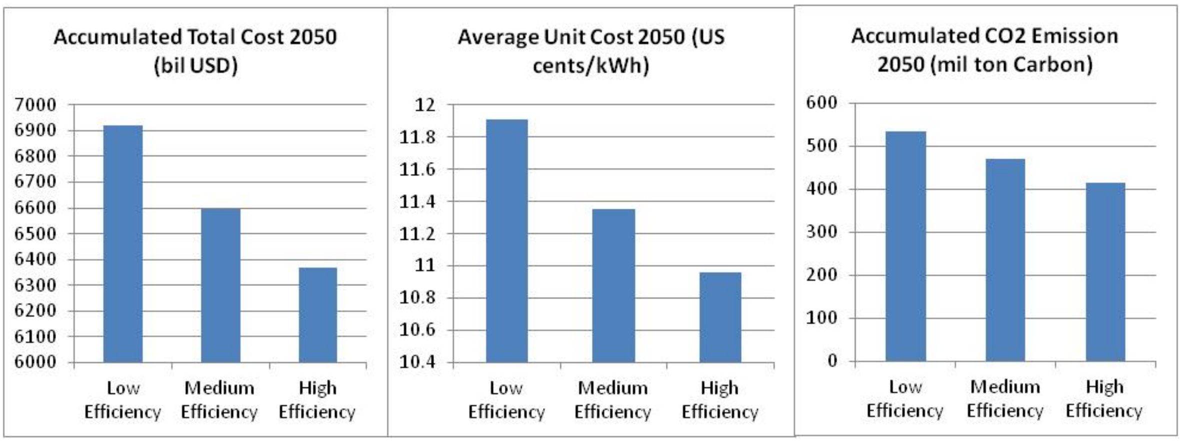


Figure 5.4.6 Implication of Grid Integration (2050)

Chapter 6 Summary and Way Forward

6.1 Summary of the Observation

With the newly constructed model, we have run simulations for optimum power mix to evaluate effects of various policy options for Vietnam, Indonesia, Philippines and the whole ASEAN region. Starting with the Reference scenario (BAU: Business as Usual case), impacts of policy actions were analyzed on energy saving, GHG emissions reduction, controlled generation mix, effect of FIT and/or fuel subsidy reduction, etc. Major findings from these analyses are as summarized below.

Vietnam

1. Coal will play a dominant role in the future energy mix. Its share in the Reference scenario will increase from 23.0% in 2014 to 51.2% in 2030 and 65.3% in 2050, while that of natural gas decreases from 44.3% in 2014 to 33.6% in 2030 and 28.5% in 2050. Price differences among fossil fuels give a big impact on selection of power mix.
2. Thus, achieving CO_2 reduction target will require higher generation cost, requiring significant switching from coal, which is cheaper, to natural gas, which is more expensive in the Asian market.
3. Improvement of thermal efficiency is the most effective solution for reducing generation cost and fossil fuel consumption, as well as for conserving domestic energy resources. It should be noted that, despite the larger initial investment, enhancing energy efficiency is more beneficial in the long run.
4. Coal-fired power plants can reduce total generation cost. Concerns are the very heavy dependence on coal-fired plants with regard to GHG emissions. Policy makers are required to find a good balance between affordability and these concerns.
5. Feed-in tariff is not effective, if it is set low, to promote renewable energies.
6. Fuel subsidy increases pressures on the state finance, while reduction in electricity unit cost for end-users is minimal. This is a touchy issue for politicians. However, for consumers, it is not more than the choice of higher tax or higher tariff.

Indonesia

1. Coal will continue to play a dominant role in the future power mix, while its share for the Reference scenario slightly decreases from 55.8% in 2014 to 51.2% in 2030 and 51.7% in 2050. Natural gas will increase its share from 21.0% in 2014 to 26.8% in 2030 and 29.4% in 2050.
2. Same for Vietnam, achieving CO_2 reduction target will require higher generation cost, requiring significant switching from coal to natural gas. Indonesia is endowed with rich coal resources and now is the world largest steaming coal exporter. On the other hand, old natural gas fields supplying piped gas to Java are depleting fast, and LNG, which is most expensive fuel for power generation, is the new supply source of gas for the future power plants.
3. Phasing out tariff subsidy could result to a lower electricity consumption compared with the

Reference scenario, under which the subsidy is in place. End users will be exposed to a higher electricity tariff, while the government will be relieved from the heavy financial burden over 5% of the GDP. As electricity demand is expanding fast in Indonesia, we should carefully examine if the present tariff subsidy would be sustainable or not.

4. Restriction on fossil fuel export, in particular export of coal, may lead to a lower generation cost while higher CO_2 emissions encouraging more coal consumption. In view that fossil fuel export can earn foreign currencies and higher revenue for the mining industry, which will be reduced to the national economy at any rate, overall impact of such policy option must be examined from much wider viewpoint.
5. Adopting power plants with higher thermal efficiency can achieve the same amount of CO_2 reduction at a lower cost in the long run.
6. Introduction of nuclear, if politically endorsed, will remain fairly below 1% in the power supply mix during the projection period, and there is least impact on the electricity sector.

Philippines

1. Coal will significantly increase its share in the power mix for the Reference scenario, from 34.4% in 2014 to 45.8% in 2030 and 69.9% in 2050. Conversely, natural gas, hydro and geothermal decrease shares due to inferior price competition and/or resource constraints.
2. The above picture does not change a lot among other cases, since renewable energy resources are relatively limited. An intensive promotion campaign would increase use of renewables only slightly in the power generation mix.
3. Effect of Feed-in Tariff was examined assuming US Cents 19/kWh for wind, US Cents 22/kWh for solar PV and US Cents 15/kWh for biomass, but it does not work. Much higher rates are required to encourage introduction of renewables.
4. High efficiency thermal plants will significantly lower fossil fuel consumption, and will reduce import dependence and GHG emissions. Despite the fact that the total cumulative cost will be slightly lower, they are not proactively chosen because of higher initial investment that requires higher financial cost.

ASEAN

1. In the power mix of ASEAN, coal will increasingly play a greater role while natural gas will continue to be a major energy source. The share of coal for the Reference scenario increases from 24.2% in 2014 to 37.0% in 2030 and 46.1% in 2050, while that of natural gas are 43.4% in 2014, 44.3% in 2030 and 37.2% in 2050. Hydro increases 70% between 2014 and 2050, but its share will decrease from 27.7% to 11.4% being not able to keep pace with electricity demand growth because of resource constraints. Renewables will increase significantly but still remain minor energy source in the power mix.
2. GHG reduction will require higher generation cost, requiring significant switching from coal to natural gas despite proactive introduction of non-fossil fuels. Supply base of renewable energies

are not substantial in the ASEAN region. We should carefully examine if such a significant cost increase could be transferred to users straightly.

3. Improvement of thermal efficiency is very effective solution for reducing generation cost and fossil fuel consumption, as well as for conserving domestic energy resources. The larger initial investment will be more than compensated over a super long period to fully cover technical life of power plants.
4. Though supply base of renewable energy is not significant in ASEAN, proactive introduction of wind and solar PV will result in reduction of electricity cost as well as GHG emissions in the long run. In addition, we may be able to expect accelerated technology progress to reduce cost of renewables if promoting measures are continuously adopted.
5. Introduction of nuclear, though politically controversial, would reduce GHG emissions significantly while the electricity cost will remain in the same range with the Reference scenario. Demand for natural gas will be eased significantly while coal consumption remains almost same. If natural gas consumption will be kept at certain level, GHG emissions reduction will be much greater.

As explained above, the model constructed in this study produces a common-sense outcome. It may be taken as a proof that the model is structured properly and working normally. As this model does not have any complicated black box, it is possible to trace accurately how the solution is derived following assumptions and incorporated technical and economic logics. Using such model, policy makers will be able to conduct evaluation of policy options without facing theoretical contradictions or magical rhetoric.

The faster the ASEAN countries develop the more important for them to set out proper energy policies and to implement them steadily step by step. To this end, we hope that this transparent model with a sense of reassurance will become a strong weapon for policy makers and energy analysts in the region.

6.2 Toward Construction of Low-carbon and Efficient Society

As outlined in this report, our much simplified model looks producing logical consequences. This model can be used for examination of policy options, and also for sensitivity analysis to find possible direction of changes and degree of impact if circumstances are changed or policies are amended. As it is developed on the popular Excel spread sheet, the user can trace the assumptions and logics how the model delivers solution clearly. We believe this transparency is very important as a tool for policy examination. Also, it is much easier to operate than LP type models which require certain experience and specific preparation of data and equations, while this model can even incorporate non-linear relationship of elements.

However, we should note that data and assumptions given to the model for each scenario are still preliminary ones. They are diverse among countries and locations, market conditions for power plant construction are changeable from time to time, and technology progresses day by day. Therefore, it is necessary to upgrade them before we proceed to the next step for substantive discussion on energy policy planning. In particular, more accurate data and information on the local conditions are essential. In addition, it is also necessary to examine whether the indicated pathway during the projection period for each scenario is sound and sustainable. We need to fine tune the model in this regard.

We trust this simplified and transparent model is handy for use for many policy makers. We hope that users will fine tune assumptions and equations up to their palates through repeated attempts. We, at IEEJ, plan to disseminate the model among ASEAN countries via various activities, and would like to upgrade it through practical application. To this end, we look forward to valuable comments and cooperation of various stakeholders.

Appendix-A: Detail Diagram for Simulation Analysis

This paper was prepared by Castalia Limited, USA, and the Institute of Energy Economics, Japan as a discussion material for examining methods to simulate impacts of energy policy options being applied or considered in the ASEAN region.

1. Vietnam

Name of Policy	Description of Policy	Instructions to Modelers	Expected Impacts on Policy Goals	Model Outputs Reflecting Expected Impacts	Model Operation Comments
Reevaluating Coal Price Distortion	Policy to increase the cost of coal supplied by the state coal company, Vinacomin, to EVN to 100 percent of Vinacomin's production cost Currently, the coal price is equal to about 85 percent of Vinacomin's production cost. From now until early 2014, it will be increased to be equal to cost recovery level	1) Specify coal price of 85 percent of Vinacomin's production cost for BAU scenario 2) Specify coal price of 100 percent of Vinacomin's production cost to model policy 3)Specify coal price at world prices to show the implicit subsidy of Vinacomin selling coal to EVN at productions cost	**Decrease affordability** by increasing the cost of fuel to generate electricity power **Increase reliability** by allowing coal suppliers to recover their costs, which will help ensure future supply **Improve efficiency** by reducing economic loss of the value of coal and sending appropriate price signals about the value of electricity generated with coal **Improve sustainability** by reducing the subsidy provided to coal generators, which will improve the viability of cleaner candidate plants such as natural gas and RE	**Total cost of supply and average electricity tariff** will show impact on affordability **Comparing the value of coal** if it were to be sold at world prices and the price that that coal receives under the existing and proposed policy will show the economic efficiency loss for Vinacomin **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different conditions to the model.** - Analysis is possible by changing coal price in the model. - International price rather than Vinacomin's production cost should be applied as criteria for the hidden subsidy. - Stepwise catch-up may be a realistic policy option. - Use of anthracite for power generation is quality give-away. - What are the local pollutants to be considered - may be SOx?

Decision No. 1393/QD-TTg: Green Growth Strategy	Policy that sets energy sector GHG emissions reductions targets compared to BAU: • 2011-2020: 10-20 percent; the voluntary reduction will be 10 percent, and 10 percent is dependent on international support 2030: 20-30 percent; voluntary reduction will be approximately 20 percent, and 10 percent is dependent on international support	1) Include constraint in model that can reduce GHG emissions resulting from power generation by a specific percentage by a specific target date 2) Set GHG emissions constraint to zero to create a BAU scenario 3) Set GHG emissions constraint to between 15 and 20 percent for 2020 and between 20 and 30 percent by 2030 to model policy	**Decrease affordability** by forcing choice of lower emission, higher cost candidate plants **Decrease reliability** by removing reliable, high emissions candidate plants **Increase sustainability** by forcing reduction of GHG emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different conditions to the model.** - Analysis is possible by setting CO2 emission volume in the model. - Please specify the local pollutants to be considered.
Decision 1474/QD-TTg: National Action Plan on Climate Change in the period 2012-2020	Policy that sets energy sector GHG emissions reductions targets of 8 percent by 2020 compared to the base year of 2005.	1) Include constraint in model that can reduce GHG emissions resulting from power generation by a specific percentage by a specific target date 2) Obtain information about GHG emissions of the electricity sector in 2005 3) Set GHG emissions constraint to 8 percent less than emissions in 2005	**Decrease affordability** by forcing choice of lower emission, higher cost candidate plants **Decrease reliability** by removing more reliable, higher emissions candidate plants **Increase sustainability** by forcing reduction of GHG emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different conditions to the model.** - Analysis is possible by setting CO2 emission volume in the model. - Changes in the share of intermittent generation would be relatively small. - Cost analysis of SOx recovery at coal thermal plant may be required.

Decision 1208/QD-TTg: RE Targets	Policy that establishes RE targets of 4.5 percent in 2020 and 6 percent in 2030	Include constraint in model to force the model to change the total electricity supply mix to include a specified percentage of RE despite potentially higher cost. Constraint should still ensure that lower cost RE will be used first	**Decrease affordability because** higher cost RE will lead to a higher cost of meeting electricity demand **Decrease reliability** if RE added to the generation matrix is intermittent **Increase sustainability** by including RE generation with no GHG emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model.** - Analysis is possible by setting generation mix in the model, as above
Decision No. 1955/QD-TTg: Nuclear Power Development	Policy that calls for commissioning the first nuclear generator by 2020. The policy also requires that nuclear power account for about 15-20 percent of the total energy consumption by 2050	1) Include nuclear generation options among candidate plant 2) Include constraint in model to force the model to change the total electricity supply mix to include a specified percentage of nuclear power 3) Set constraint to 15-20 percent nuclear power	**Uncertain impact on affordability** because it is unclear if nuclear candidate plant will be more or less expensive than alternative candidate plant **Increase reliability** by including a large, reliable candidate plant in the generation mix **Increase sustainability** because nuclear candidate plants do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model.** Analysis is possible by setting generation mix in the model.

Decision No. 18/2008/QD-BCT: Avoided Cost Tariff Act Regulation	Policy that sets FITs for RE at avoided cost. In 2012, the average avoided cost tariff was US$0.056	1) Model avoided costs of providing electricity for each year the model will consider 2) Set value for FIT at avoided cost of generating electricity for each year the model will consider 3) Create constraint that requires that RE candidate plant that are less expensive per kWh than the FIT to be included in the generation mix	**Improve affordability** by including least cost RE candidate plants **Decrease reliability** by adding more intermittent RE candidate plant to the grid **Increase sustainability** by introducing RE candidate plant that do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** - Analysis is possible by setting FIT in the model. - Changes in the overall generation cost would be relatively subtle, while accurate estimation of RE generation cost is required.
Decision No. 37/2011/QD-TTg: Vietnam Wind Feed-In Tariff	Policy that sets FIT of $0.087/kWh for wind energy. The FIT will be offered under a PPA that must have a term of 20 years	See discussion of modeling FITs.	**Decrease affordability** by introducing wind energy at a higher cost than alternative candidate plants **Decrease reliability** by adding more intermittent candidate wind energy plants to the grid **Increase sustainability** by introducing candidate wind energy plants that do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** - Analysis is possible by setting FIT in the model. - Changes in the overall generation cost would be relatively subtle, while accurate estimation of RE generation cost is required.

Biomass Feed-In Tariff	Proposed policy that sets a FIT for biomass combined heat and power (CHP) of US$0.056 per kWh	See discussion of modeling FITs.	**Decrease affordability** by introducing candidate biomass CHP plant at a higher cost than alternative candidate plants **Increase sustainability** by introducing candidate biomass CHP plants that do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation** in generation mix will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** - Changes in the overall generation cost would be relatively subtle, while accurate estimation of RE generation cost is required.
Decision No. 130/2007/QD-TTg: CDM Project Incentives	Policy that exempts CDM projects from import taxes and the Land Use Levy. In addition, it stipulates that they pay a lower corporate income tax of 10 percent. They are also permitted to depreciate their assets 50 percent faster than normal	1) Include variables to specify the cost of import taxes, investment taxes, and the Land Use Levy in investment cost for all candidate plant 2) Reduce variables for taxes and levies for candidate RE projects that qualify for CDM according to policy	**Increase affordability** by lowering cost of RE candidate plant; though it may increase cost to the government through revenue loss **Decrease reliability** by introducing more intermittent RE **Increase widespread access** by lowering the cost of RE installations in off-grid areas **Increase sustainability** by introducing candidate RE plant that do not emit GHGs	**Total cost of supply** and **average electricity tariff** will show if impact on affordability is positive or negative for customers **Reductions in tax revenue** will show impact on affordability for government **Share of intermittent generation** in generation mix will show impact on reliability **Reduction in cost of distributed generation RE** will show impact on widespread access **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model, or cost data inputs may be varied according to Cash Flow Analysis run separately.** - Analysis is possible by setting subsidy, tax, etc. in the model. **-** In-depth study and customized model will be necessary to discuss the issue precisely.

Decree 75/2011/ND-CP : Export Credits for RE Projects	Policy establishes that RE projects will be entitled to state investment and export credits with interest rates equivalent to a five-year government bond plus 1 percent	1) Include a variable to apply a different discount rate to each candidate plant 2) Lower the discount rate for RE generation options to the cost of a five-year government bond plus 1 percent	**Increase affordability** by lowering cost of RE candidate plant; though it may increase cost to the government if loans credits are not recoverable **Decrease** reliability by introducing more intermittent RE **Increase widespread access** by lowering the cost of RE installations in off-grid areas **Increase sustainability** by introducing candidate RE plants that do not emit GHGs	**Total cost of supply** and **average electricity tariff** will show if impact on affordability is positive or negative for customers **Losses from unrecoverable credits** will show impact on affordability for government **Share of intermittent generation** will show impact on reliability **Reduction in cost of distributed generation RE** will show impact on widespread access **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model, or cost data inputs may be varied according to Cash Flow Analysis run separately.** - Analysis is possible by setting subsidy, tax, etc. in the model. - The title should read “Investment Credits and Export Credits,” and the former is applicable for our study. - Is it state investment or institutional loan?
Vietnam National Energy Efficiency Program	Policy that promotes RE in target industries—industrial, commercial, residential, and transport—to achieve nationwide energy efficiency savings of 5-8 percent by 2015	Reduce variable for total demand by 5-8 percent by 2015	**Increase affordability** by lowering electricity that must be generates **Increase reliability** by reducing strains on generation **Increase sustainability** by reducing GHG emissions that would have been emitted to meet higher demand	**Total cost of supply** will show if impact on affordability **Reductions in total capacity** required to meet electricity demand will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different demand outlooks to the model.** - Analysis is possible by changing electricity demand in the model. But this model is power supply optimization model. Therefore, it is not possible to analyze for nationwide energy efficiency saving.

2. Indonesia

Name of Policy	Description of Policy	Instructions to Modelers	Expected Impacts on Policy Goals	Model Outputs Reflecting Expected Impacts	Model Operation Comments
Electricity Law (No. 30/2009)	Policy that establishes a target energy mix of: • Oil <20% • Gas <30% • Coal <33%; • Biofuel >5% • Geothermal >5% • RE >5% • Liquefied Coal >2%	Include constraint in model to force the model to change the total electricity supply mix to include a specified percentage of each candidate plant fuel type despite higher costs	**Decrease affordability** because forcing the model to accommodate specified percentages of candidate plant types will prevent the model from choosing the least cost expansion plan **Uncertain effect on reliability** because shifting away from oil could increase energy security; however, introducing RE could adversely affect reliability by introducing additional intermittent energy **Uncertain impact on sustainability** because shifting from oil to coal will increase GHG; however including RE generation with no GHG emissions could lower emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model.** - Liquefied coal is an alternate energy source for vehicles, but not for power generation. - Rather, IGCC (Integrated coal Gasification Combined Cycle) is an advanced coal use in power generation. - IGCC is an expensive process, and may be considered under severe conditions for air quality and fuel efficiency. 4. For detail discussion, precise estimation of localized cost will be necessary. - Operation: The model was designed to accommodate restrictions such as target of energy mix. We can develop a scenario to reflect the target energy mix. The total cost of supply and average electricity tariff under a certain energy mix are part of the model's output. Share of

					intermittent generation in generation mix and the GHG and local pollutant emissions can also be calculated based on the output of the model. However, quantitative analysis of intermittent generation's impact on reliability is considered out the scope. **-** Issues:- Is the target energy mix based on electricity generation or based on primary energy?

Energy Law (No. 30. 2007): Electricity Tariff Subsidy Reduction	Policy that calls for reducing subsidies until tariffs reflect the economic price of electricity	1) Include in the model a relationship between tariff price increases and reduced demand 2) Assume that demand is reduced equivalent in relation to the rise in tariffs	**Decrease affordability** for consumers as tariffs rise; however, the burden on the Government will be reduced **Increase reliability** by making PLN's operations financially sustainable **Increase efficiency** by sending appropriate price signals to consumers encouraging them not to waste electricity **Increase sustainability** by reducing demand for electricity and which will limit GHG emissions	**Total cost of supply** will show impact on affordability for the Government **Average tariff** will show impact on affordability for the consumer **Total cost of supply** will show reallocation of resources to other more productive uses **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model.** - Price effect on demand is simulated in the model though it may be overwhelmed by income effect and hence assumptions for economic growth. **-** Analysis of demand elasticity to tariff was done based on historical data. Future demand projection was linked to the tariff change. Total supply cost and the average tariff without subsidy are part of the model's output. GHG and local pollutant emissions can also be calculated based on the output of the model.

Ministry of Energy and Mineral Resources Decree No. 04: Feed-In Tariff	Policy that establishes FITs for various RE generation candidate plant under 10 MW based on the avoided cost of the grid in which it is introduced: • RE: US$ 0.0713-0.1637 • Biomass: US$ 0.106-0.1872 • Waste to energy: US$ 0.09-0.15 • Geothermal: US$0.1-0.185	See discussion of modeling FITs.	**Decrease affordability** by introducing candidate RE plant at a higher cost than alternative candidate plants **Decrease reliability** by adding more intermittent candidate RE plant to the grid **Increase sustainability** by introducing candidate RE plants that do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different conditions to the model.** **- Changes in the overall generation cost would be relatively subtle, while accurate estimation of RE generation cost is required.** - The overall supply and average electricity tariff will be calculated based on the designated tariff for a certain technology though the cost of which is calculated from its CAPEX and OPEX by default in the model. -Issues: ・Since the purchasing period of renewable electricity under the FIT was not specified, is it OK to set it at 20 years? ・Is the FIT supposed to be in force over the projection period (through 2050) or will it be phased out at some point? If it is going to be phased out, around which year? ・The smallest geothermal power plant is supposed to be 100MW. Is the tariff still applicable?

Solar Energy Auction Program	Policy that allows PLN to auction off up to 172.5MW of installed solar capacity to candidate solar project developers to bid at a discount to the state-set top price of US$0.25 per kWh. Winning bids will sign 20-year contracts to sell power to state utility	1) Model the cost of candidate solar PV plants 2) Assume that candidate solar PV plant the cost of which is less thantUS$0.25 per kWh will have their bids accepted starting with the least expensive bid until the maximum installed capacity of 172.5 MW is reached	**Decrease affordability** by introducing candidate RE plant at a higher cost than alternative candidate plant **Decrease reliability** by adding more intermittent candidate RE plant to the grid **Increase sustainability** by introducing candidate RE plant that do not emit GHGs	**Total cost of supply and average electricity tariff** will show if impact on affordability is positive or negative **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different conditions to the model.** - As changes in the overall generation cost will be subtle, accurate cost/price assumptions are required. - The cost of PV plant candidate solar PV plant can be calculated in the model. And the resulted supply cost and average electricity tariff can also be calculated. - Issues: Given the small scale of the solar capacity compared with the country's power generation capacity it is supposed that the impact will be very small. The installation year of the PV systems need to be specified. More information about the candidate PV plants needs to be provided: such as the capacity, capacity factor, and so on.

International Interconnection	Policy that calls for establishing interconnection between Sumatra and Malaysian Peninsula and between Kalimantan and Serawak	1) Research the average cost of generation in the Malaysian Peninsula and Serawak 2) Include generation from Serawak and the Malaysian peninsula as candidate plants in the energy mix of Sumatra and Kalimantan	**Uncertain impact on affordability** because average costs of generation and the price that Serawak and Malaysia would be willing to sell electricity are unknown **Increase Efficiency** because if Indonesia or its trading partners can produce electricity more efficiently, all countries will benefit from the efficiency gain	**Total cost of supply** and **average electricity tariff** will show if impact on affordability and on efficiency	**OK: Run cases with and without linkage. Benefit of linkage can be calculated as the cost difference between an aggregate demand case and separate demand cases combined, which may be compared to the linkage cost.** **-** Regional demand outlook is necessary. Physical linkage cost may be studied separately. (Due to the scarcity of data and information we prefer not to do this analysis at current stage)

Domestic Interconnection	Policy that call for improving the Java-Sumatra interconnection	Consider candidate plant in Sumatra, Java, and Bali as eligible for meeting the electricity needs of Sumatra, Java, and Bali	**Increase affordability** because PLN will be able to place power assets where it is most advantageous to supply power to the three islands **Increase Efficiency** because if one of the three islands can produce electricity more efficiently, all islands will benefit from the efficiency gain	**Total cost of supply** and **average electricity tariff** will show if impact on affordability and on efficiency	**Same as above.** **- Scale merit of generation cost on plant size is another key assumption.** **-** Besides the national electricity demand and supply model, we are also going to develop local electricity demand and supply models for Sumatra and Java-Bali. The output difference between the national model and the aggregation of the local models can give us some implications about the impact of domestic interconnection. **-** This approach is still under discussion and we need an investigation of data availability.

DEN Draft Energy Policy: High RE Energy Mix Targets	Policy that establishes a target energy mix of: • Gas: 20 percent by 2025; and 14 percent by 2050 • Oil: 23 percent by 2025; 16 percent by 2050 • Coal: 30 percent by 2025; 30 percent by 2050 • RE: 26 percent by 2025; 39 percent by 2050	Include constraint in model to force the model to change the total electricity supply mix to include a specified percentage of each candidate plant fuel type despite higher costs	**Decrease affordability because** higher cost RE will lead to a higher cost of meeting electricity demand **Decrease reliability** if RE added to the generation matrix is intermittent **Increase sustainability** by including significantly more RE candidate plants with no GHG emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as condition to the model.** **-** Precise cost estimation is the key to the result. - The relationship between the reliability and RE share needs to be studied. - We can develop a scenario to reflect the target energy mix. And the required cost of supply, average electricity tariff, share of intermittent generation, and GHG and local pollutant emissions under the scenario can be calculated. - Issues: Is the energy mix based on electricity generation or based on primary energy? If it is based on primary energy, what is the mix for power generation?

DEN Proposed Coal and Gas Export Restrictions	Policy that calls on the Government to cut gas and coal exports so that they can be used domestically	1) Model that allows changing cost of coal and gas if export restrictions are imposed 2) Adjust the values for cost of coal and gas in the model	**Increase affordability** for by reducing the cost of fuels for gas and coal candidate plant **Decrease efficiency** by reducing the economic benefit realized from exploiting Indonesia's resources **Decrease sustainability** by lowering the cost of coal and gas candidate plant, which will reduce the competitiveness of RE candidate plant	**Total cost of supply** and **average electricity tariff** will show impact on affordability **Comparing the value of natural gas and coal** if it were to be exported at world prices and the price that that natural gas and coal will receive in exports are restricted will show the economic efficiency loss **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** **-** Discussion on the local and export prices of resources is the key to the output. - Fuel cost can is changeable in the model. And the resulted cost of supply, average electricity tariff, and GHG and local pollutant emissions can be calculated. - Issues: ・The resulted domestic price of coal and natural gas will be required. ・Though the fiscal impact from lowered fuel cost can be calculated from the model's output, the fiscal impact from reduction of coal and natural gas export is out of the scope of the model.

DEN Proposed GHG Reductions	Policy that establishes a GHG emissions reductions target of 26% by 2020 under BAU scenario	1) Include constraint in model that can reduce GHG emissions resulting from power generation by a specific percentage by a specific target date 2) Set GHG emissions constraint to zero to create a BAU scenario 3) Set GHG emissions constraint to 26 percent for 2020	**Decrease affordability** by forcing choice of lower emission, higher cost candidate plant **Decrease reliability** by removing reliable, high emissions candidate plant **Increase sustainability** by forcing reduction of GHG emissions	**Total cost of supply and average electricity tariff** will show impact on affordability **Share of intermittent generation in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** - The GHG emissions reduction target will be translated into restriction on certain power generation technologies, which forms a new scenario. The total cost of supply, average electricity tariff, share of intermittent generation, and GHG and local pollutant emissions under the new scenario can be calculated. - Information on the amount of GHG emissions from power generation under different scenarios is required.

3. Philippines

Name of Policy	Description of Policy	Instructions to Modelers	Expected Impacts on Policy Goals	Model Outputs Reflecting Expected Impacts	Model Operation Comments
Draft Renewable Portfolio Standards Policy, August 2013 (at least three year transition period is envisioned before implementation)	Each market supplier (distribution utilities, retail electricity suppliers) will be given a different target, based on its electricity supply portfolio. RPS target expected to increase by 1 percent annually. Renewable Energy Certificates can be bought to meet shortfalls. DoE will grant exceptions for meeting targets, if lack of RE capacity or available supply on market. Eligible technologies include: biomass, waste-to-energy, wind energy, solar energy, run-of-river hydro, ocean energy, hybrid systems, impounding hydropower that meet international standards, geothermal	Include constraint in model to force the model to change the total electricity supply mix to include a specified percentage of RE despite potentially higher cost. Constraint should still ensure that lower cost RE will be used first	**Decrease affordability** since costs of generation will increase if more expensive RE is prioritized, and more investments in ancillary capacity have to be made. Consumers may pay more, given that higher generation costs per KWh will be reflected in electricity tariffs **Decrease reliability** by adding more intermittent RE candidate plants to grid **Increase sustainability** if RE plants with no emissions are substituting polluting baseload and ancillary plants	**Total cost of supply** and **average electricity tariff** will show impact on affordability **Share of intermittent energy in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run optional cases changing assumptions.** - Availability of domestic natural gas or LNG import facility (including pipelines) is a key to the future generation mix. - Is it possible to use existing hydro power not under control of NPC to accommodate intermittent REs? - Precise cost estimation is a key to the result. - Through the setting of constraints (minimum power generation capacity of RE, etc), RE will be forced introduce. The model will show the simulation result of average electricity tariff, supply cost ,generation mix, amount of GHG and others.

Approved Feed-in Tariff Policy, July 2012	FITs currently determined based on total average costs of building, operating and connecting "new" RE plants to the grid. In 2012, run-of-river hydropower (US$0.13/KWh), biomass (US$0.15/KWh), wind (US$0.19/KWh), solar (US$ 0.22/KWh). Ocean eligible but FIT rate not set (can assume higher than solar). FITs lowered if actual installed capacity per technology exceeds expected amount. A uniform "FIT-all" tariff applied to electricity consumers, based on per kWh consumption	See discussion of modeling FITs. Also, include the option to drop FITs, and revert to least cost generation if/when generation mix reaches target capacity: By 2030, FIT targets are run-of-river hydro: 250MW, biomass: 250MW, wind: 200MW, solar: 50MW, Ocean: 10MW	**Decrease affordability** since more expensive RE allowed in mix may increase generation costs and therefore tariffs **Decrease reliability** by adding more intermittent RE candidate plants to grid **Increase sustainability** if. RE plant with no emissions are substituting polluting baseload and ancillary plants	**Total cost of supply** and **average electricity tariff** will show impact on affordability **Share of intermittent energy in generation mix** will show impact on reliability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Give as conditions to the model.** - Precise cost estimation is a key to the result. - Based on the Philippines statistics data, it could be completed. The result will show the changing of average electricity tariff. - Through a case study, all of result will be shown.
Labeling and Standardization Program and Minimum Energy Performance Standards (these programs part of Comprehensive National Energy Efficiency and Conservation Program (NEECP), 2004)	Policy applied to home appliances refrigerators and freezers, window-type air conditioners, CFLs, linear fluorescent lamps, ballasts, washers/dryers, audio-video equipment. This measure alone expected to reduce cumulative energy consumption between 2010 and 2030 by 150.3 TWh, which forms roughly 45 percent of Philippines' goal of achieving total energy savings of 10 percent by 2030	Whichever method for reporting electricity savings is chosen, set the amount of electricity saved between 2010 to 2030 to be 150.3TWh Two alternative methods: 1) if demand is projected based on electricity consumption per customer type, then consumption for households should fall. Scenarios can be created around the extent to which demand can fall. If demand is projected using a growth rate, the growth rate in demand can be varied. However	**Increase affordability** by lowering electricity that must be generated **Increase reliability** by reducing strains on generation **Increase sustainability** by reducing GHG emissions that would have been emitted with higher demand	**Total cost of supply** will show impact on affordability **GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different demand outlooks reflecting the program.** - Energy conservation may reduce consumption of more expensive fossil fuel for power generation. - The electricity demand forecast model will estimate electricity demand by sector (Industrial, commercial and residential), and then sum all of sector. Through a case study (with or

		make sure cost of program included 2) if energy efficiency can be put in as ‘negative MW’ as a candidate generating facility, the MWs can be changed			without introduce standard), changed of total supply cost will be shown.
Proposed Coal Import Restrictions (date unknown)	No official policy or program proposed by Government. Some sources indicate the Government has made efforts to limit coal imports by 20 percent. Philippines currently imports 75 percent of coal and buys on international markets. 96 percent of domestic coal provided by Semirara coal field, but mainly low-grade	1) Assume two types of coal—high grade imported at world coal prices, and low grade domestic at Semirara prices but including transport costs. Also include different thermal efficiencies for each 2) Set 55 percent domestic supply, and 45 imported 3) For BAU assume 75 percent imported and 25 percent domestic 4) If possible, assign different GHG and local emissions for plants using more polluting local versus cleaner imported coal	**Decrease affordability** since increasing use of lower efficiency and high cost local coal will increase the costs of producing electricity from coal **Decrease efficiency** because using lower quality Philippine coal at uneconomic costs will result in higher electricity costs **Uncertain impact on sustainability** depending on whether there is a switch from using coal to using a less polluting generation technology, or if the total generation mix remains unchanged and low grade coal is being used instead	**Total cost of supply** will show impacts on affordability **Comparing cost of using local coal and imported coal** purchased at world prices will show the economic efficiency loss **Generation mix, GHG and local pollutant emissions** will show impact on sustainability	**OK: Run cases giving different demand outlooks to the model.** - Prices of coal in Philippines are mostly same with international coal price adjusted to quality, while Semirara coal is of low quality and needs blending high quality coal at use. The blending ratio is a technical matter rather than a policy objective. - Coal import restriction looks eccentric and unrealistic. - Philippines coal prices are nearly the same as international prices (if changing to common heat value). In the model, common unit will be used (USD/toe or USD/kWh). Also, I think the economic efficiency loss is very smaller.

Proposed Mindanao and Visayas (Leyte-Mindanao Interconnection Project), 500MW capacity, March 2013	Visayas and Luzon already connected (total capacity 1240 MW). Interconnection infrastructure between Mindanao and Visayas which includes a 455km overhead line and a 23km submarine cable proposed. Initial investment projected to be US$300 million, but feasibility studies (US$2 million costs) pending	1) Consider candidate plant in Visayas, Luzon, and Mindanao as eligible for meeting the electricity needs of all three grids 2) Link higher total generation costs (more expensive peaker) plants to tariffs to show increase	**Increase affordability** for the grid since lower production costs in Mindanao could spread to the rest of the country **Increase reliability** since total reserve capacity available in system increases **Increase efficiency** because if one of the interconnected grids can produce electricity more efficiently, all of the grids will benefit from the efficiency gain	**Total cost of supply** and **average tariff** will show if there is an impact on affordability and on efficiency	**OK: Run cases with and without linkage. Benefit of linkage can be calculated as the cost difference between an aggregate demand case and separate demand cases combined, which may be compared to the linkage cost.** **- Regional demand outlook is necessary. Physical linkage cost may be studied separately.** - It is needed to estimate electricity demand and supply by the three regions. Comparing with national result the targeted policy could be explained. - Amount of work is large.

Appendix-B: Energy Outlook of ASEAN Countries

\- IEEJ Asia/World Energy Outlook 2013 –

The detail report is available at the IEEJ's website at:
http://eneken.ieej.or.jp/en/whatsnew/413.html

1. World Primary Energy Consumption

(Mtoe)

	Historical			Projection			CAGR (%)				
	1990	2000	2011	2020	2030	2040	1990/ 2011	2011 2020	2020/ 2030	2030/ 2040	2011/ 2040
Asia	**2,120** (24.1)	**2,934** (29.1)	**5,058** (38.6)	**6,339** (41.7)	**7,663** (43.7)	**8,931** (45.5)	4.2	2.5	1.9	1.5	2.0
P. R. China	**871** (9.9)	**1,161** (11.5)	**2,728** (20.8)	**3,433** (22.6)	**4,009** (22.9)	**4,423** (22.5)	5.6	2.6	1.6	1.0	1.7
India	**317** (3.6)	**457** (4.5)	**749** (5.7)	**1,011** (6.6)	**1,403** (8.0)	**1,896** (9.7)	4.2	3.4	3.3	3.1	3.3
Japan	**439** (5.0)	**519** (5.1)	**461** (3.5)	**466** (3.1)	**449** (2.6)	**425** (2.2)	0.2	0.1	-0.4	-0.6	-0.3
Korea	**93** (1.1)	**188** (1.9)	**260** (2.0)	**290** (1.9)	**309** (1.8)	**310** (1.6)	5.0	1.2	0.6	0.0	0.6
Chinese Taipei	**48** (0.5)	**85** (0.8)	**109** (0.8)	**121** (0.8)	**128** (0.7)	**130** (0.7)	3.9	1.2	0.6	0.1	0.6
ASEAN	**233** (2.6)	**377** (3.7)	**557** (4.2)	**767** (5.0)	**1,038** (5.9)	**1,349** (6.9)	4.2	3.6	3.1	2.7	3.1
Indonesia	**99** (1.1)	**155** (1.5)	**209** (1.6)	**301** (2.0)	**413** (2.4)	**547** (2.8)	3.6	4.1	3.2	2.8	3.4
Malaysia	**22** (0.2)	**47** (0.5)	**76** (0.6)	**102** (0.7)	**129** (0.7)	**152** (0.8)	6.2	3.3	2.4	1.6	2.4
Myanmar	**11** (0.1)	**13** (0.1)	**14** (0.1)	**20** (0.1)	**27** (0.2)	**33** (0.2)	1.3	3.9	3.0	2.2	3.0
Philippines	**29** (0.3)	**40** (0.4)	**40** (0.3)	**49** (0.3)	**66** (0.4)	**87** (0.4)	1.7	2.3	2.9	2.8	2.7
Singapore	**12** (0.1)	**19** (0.2)	**33** (0.3)	**42** (0.3)	**50** (0.3)	**56** (0.3)	5.2	2.5	1.8	1.1	1.8
Thailand	**42** (0.5)	**72** (0.7)	**119** (0.9)	**158** (1.0)	**205** (1.2)	**263** (1.3)	5.1	3.2	2.6	2.5	2.8
Vietnam	**18** (0.2)	**29** (0.3)	**61** (0.5)	**91** (0.6)	**144** (0.8)	**207** (1.1)	6.0	4.5	4.7	3.7	4.3
Asia excl. Japan	**1,680** (19.1)	**2,415** (24.0)	**4,596** (35.0)	**5,873** (38.6)	**7,214** (41.2)	**8,506** (43.3)	4.9	2.8	2.1	1.7	2.1
North America	**2,124** (24.2)	**2,525** (25.0)	**2,443** (18.6)	**2,494** (16.4)	**2,580** (14.7)	**2,625** (13.4)	0.7	0.2	0.3	0.2	0.2
United States	**1,915** (21.8)	**2,273** (22.5)	**2,191** (16.7)	**2,234** (14.7)	**2,299** (13.1)	**2,327** (11.8)	0.6	0.2	0.3	0.1	0.2
Latin America	**467** (5.3)	**599** (5.9)	**809** (6.2)	**1,024** (6.7)	**1,284** (7.3)	**1,508** (7.7)	2.7	2.7	2.3	1.6	2.2
OECD Europe	**1,619** (18.4)	**1,747** (17.3)	**1,756** (13.4)	**1,806** (11.9)	**1,847** (10.5)	**1,860** (9.5)	0.4	0.3	0.2	0.1	0.2
European Union	**1,636** (18.6)	**1,685** (16.7)	**1,654** (12.6)	**1,699** (11.2)	**1,737** (9.9)	**1,753** (8.9)	0.1	0.3	0.2	0.1	0.2
Non-OECD Europe	**1,537** (17.5)	**1,003** (10.0)	**1,176** (9.0)	**1,273** (8.4)	**1,380** (7.9)	**1,464** (7.5)	-1.3	0.9	0.8	0.6	0.8
Africa	**392** (4.5)	**502** (5.0)	**700** (5.3)	**850** (5.6)	**1,037** (5.9)	**1,252** (6.4)	2.8	2.2	2.0	1.9	2.0
Middle East	**223** (2.5)	**376** (3.7)	**670** (5.1)	**828** (5.4)	**1,027** (5.9)	**1,223** (6.2)	5.4	2.4	2.2	1.8	2.1
Oceania	**99** (1.1)	**125** (1.2)	**141** (1.1)	**152** (1.0)	**160** (0.9)	**165** (0.8)	1.7	0.9	0.5	0.3	0.5
OECD	**4,511** (51.4)	**5,274** (52.3)	**5,282** (40.3)	**5,484** (36.0)	**5,685** (32.5)	**5,795** (29.5)	0.8	0.4	0.4	0.2	0.3
Non-OECD	**4,070** (46.3)	**4,537** (45.0)	**7,471** (57.0)	**9,283** (61.0)	**11,294** (64.5)	**13,234** (67.4)	2.9	2.4	2.0	1.6	2.0
World	**8,782** (100)	**10,082** (100)	**13,113** (100)	**15,216** (100)	**17,517** (100)	**19,642** (100)	1.9	1.7	1.4	1.2	1.4

Source: IEA "World Energy Balances"
Projection by IEEJ

Note: Figures in parentheses are global shares (%). World includes international bunkers.

2. ASEAN

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	142	233	377	557	767	1,038	1,349	100	100	100	4.2	3.6	3.1	2.7	3.1
Coal	3.6	12	32	90	146	221	321	5.4	16	24	9.9	5.5	4.3	3.8	4.5
Oil	58	88	153	206	283	355	436	38	37	32	4.1	3.6	2.3	2.1	2.6
Natural gas	8.4	29	71	117	176	246	329	13	21	24	6.8	4.6	3.4	2.9	3.6
Nuclear	-	-	-	-	-	9.4	20	-	-	1.5	n.a.	n.a.	n.a.	7.9	n.a.
Hydro	0.8	2.3	4.1	6.3	8.0	10	11	1.0	1.1	0.8	4.8	2.8	2.3	0.9	2.0
Geothermal	1.8	6.6	18	25	33	51	69	2.9	4.4	5.1	6.5	3.2	4.5	3.1	3.6
Solar, wind, etc.	-	-	-	0.0	0.1	0.2	0.7	-	0.0	0.1	n.a.	20.9	5.7	11.4	12.2
Biomass and waste	70	93	98	112	120	142	159	40	20	12	0.9	0.8	1.7	1.2	1.2

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	112	173	271	406	558	743	953	100	100	100	4.1	3.6	2.9	2.5	3.0
By sector															
Industry	22	43	77	119	177	254	339	25	29	36	5.0	4.6	3.7	2.9	3.7
Transport	17	32	62	97	141	192	249	19	24	26	5.4	4.2	3.1	2.6	3.3
Buildings, etc.	71	87	112	136	167	211	266	50	33	28	2.1	2.3	2.4	2.4	2.3
Non-energy use	2.4	11	21	54	73	86	98	6.6	13	10	7.7	3.4	1.7	1.3	2.1
By energy															
Coal	2.1	6.1	14	35	58	83	109	3.5	8.6	11	8.7	5.8	3.5	2.8	4.0
Oil	41	67	124	186	252	325	405	38	46	43	5.0	3.4	2.5	2.2	2.7
Natural gas	2.5	7.4	17	33	51	74	102	4.3	8.3	11	7.4	4.7	3.9	3.2	3.9
Electricity	4.7	11	28	53	83	130	191	6.4	13	20	7.7	5.1	4.6	3.9	4.5
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	62	82	89	98	114	132	145	47	24	15	0.9	1.7	1.5	1.0	1.4

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	62	154	370	694	1,071	1,668	2,448	100	100	100	7.4	4.9	4.5	3.9	4.4
Coal	3.0	28	79	216	357	595	951	18	31	39	10.3	5.8	5.2	4.8	5.3
Oil	47	66	72	71	70	71	72	43	10	3.0	0.3	-0.1	0.1	0.2	0.1
Natural gas	0.7	26	154	307	497	752	1,067	17	44	44	12.6	5.5	4.2	3.6	4.4
Nuclear	-	-	-	-	-	45	104	-	-	4.2	n.a.	n.a.	n.a.	8.7	n.a.
Hydro	9.8	27	47	73	94	118	129	18	11	5.3	4.8	2.9	2.3	0.9	2.0
Geothermal	2.1	6.6	16	19	38	59	80	4.3	2.8	3.3	5.3	7.8	4.5	3.1	5.0
Other renewables	-	0.6	1.0	7.9	16	29	46	0.4	1.1	1.9	13.1	8.0	6.2	4.7	6.2

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	400	694	1,120	1,938	3,125	4,890	7,061	5.0	5.5	4.6	3.7	4.6
Population (million)	348	430	504	577	635	687	725	1.4	1.1	0.8	0.5	0.8
CO_2 emissions[*2] (Mt)	205	358	703	1,105	1,643	2,291	3,091	5.5	4.5	3.4	3.0	3.6
GDP per capita ($2010 thousand)	1.1	1.6	2.2	3.4	4.9	7.1	9.7	3.5	4.3	3.8	3.2	3.7
Primary energy consump. per capita (toe)	0.4	0.5	0.7	1.0	1.2	1.5	1.9	2.8	2.5	2.3	2.1	2.3
Primary energy consumption per GDP[*3]	356	335	336	287	246	212	191	-0.7	-1.7	-1.4	-1.0	-1.4
CO_2 emissions per GDP[*2, *4]	512	516	628	570	526	468	438	0.5	-0.9	-1.2	-0.7	-0.9
CO_2 per primary energy consumption[*2, *5]	1.4	1.5	1.9	2.0	2.1	2.2	2.3	1.2	0.9	0.3	0.4	0.5
Automobile ownership (million)	4.5	10	21	45	67	98	138	7.4	4.6	3.8	3.5	4.0
Automobile ownership rates[*6]	13	24	41	78	106	143	191	5.9	3.5	3.0	3.0	3.1

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million,
*4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

3. Vietnam

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	14	18	29	61	91	144	207	100	100	100	6.0	4.5	4.7	3.7	4.3
Coal	2.3	2.2	4.4	16	26	42	67	12	25	32	9.7	5.7	5.1	4.8	5.2
Oil	1.8	2.7	7.8	21	31	47	64	15	33	31	10.1	4.7	4.2	3.2	4.0
Natural gas	-	0.0	1.1	7.4	13	23	35	0.0	12	17	45.8	6.5	5.6	4.4	5.4
Nuclear	-	-	-	-	-	6.6	12	-	-	5.6	n.a.	n.a.	n.a.	5.9	n.a.
Hydro	0.1	0.5	1.3	2.6	4.0	5.3	6.0	2.6	4.2	2.9	8.5	5.0	2.9	1.2	2.9
Geothermal	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Solar, wind, etc.	-	-	-	0.0	0.0	0.0	0.1	-	0.0	0.0	n.a.	12.5	3.8	6.4	7.3
Biomass and waste	10	12	14	15	17	20	23	70	24	11	0.8	1.5	1.7	1.4	1.5

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	13	16	25	51	75	115	160	100	100	100	5.7	4.4	4.3	3.4	4.0
By sector															
Industry	3.8	4.5	7.9	18	28	44	63	28	35	39	6.8	4.8	4.9	3.5	4.4
Transport	0.6	1.4	3.5	11	18	25	33	8.6	22	21	10.4	5.3	3.6	2.8	3.9
Buildings, etc.	8.6	10	14	19	25	38	54	63	37	34	3.0	3.4	4.1	3.6	3.7
Non-energy use	0.0	0.0	0.1	3.2	4.7	7.2	10	0.2	6.3	6.3	25.4	4.4	4.3	3.4	4.0
By energy															
Coal	1.5	1.3	3.2	10	16	27	39	8.3	20	24	10.3	4.9	5.2	3.9	4.7
Oil	1.7	2.3	6.5	19	30	46	63	15	37	40	10.5	5.3	4.4	3.3	4.3
Natural gas	-	-	0.0	0.5	0.6	0.8	1.1	-	0.9	0.7	n.a.	3.0	3.0	3.0	3.0
Electricity	0.2	0.5	1.9	7.8	13	22	35	3.3	15	22	13.7	5.6	5.8	4.5	5.3
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	9.7	12	13	14	16	19	22	74	27	14	0.7	1.6	1.7	1.5	1.6

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	3.6	8.7	27	99	163	285	444	100	100	100	12.3	5.7	5.8	4.5	5.3
Coal	1.4	2.0	3.1	21	41	69	130	23	21	29	11.8	7.6	5.4	6.6	6.5
Oil	0.7	1.3	4.5	4.7	4.3	3.9	3.5	15	4.8	0.8	6.3	-1.0	-1.0	-1.0	-1.0
Natural gas	-	0.0	4.4	44	72	125	195	0.1	44	44	52.7	5.7	5.8	4.5	5.3
Nuclear	-	-	-	-	-	25	45	-	-	10	n.a.	n.a.	n.a.	5.9	n.a.
Hydro	1.5	5.4	15	30	46	61	69	62	30	16	8.5	5.0	2.9	1.2	2.9
Geothermal	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Other renewables	-	-	-	0.1	0.4	0.5	0.9	-	0.1	0.2	n.a.	11.0	4.2	5.5	6.7

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	15	25	53	113	185	344	549	7.3	5.7	6.4	4.8	5.6
Population (million)	54	66	78	88	95	99	102	1.4	0.9	0.5	0.2	0.5
CO_2 emissions[*2] (Mt)	15	17	43	132	213	342	514	10.2	5.4	4.8	4.2	4.8
GDP per capita ($2010 thousand)	0.3	0.4	0.7	1.3	1.9	3.5	5.4	5.9	4.8	5.9	4.5	5.1
Primary energy consump. per capita (toe)	0.3	0.3	0.4	0.7	1.0	1.4	2.0	4.6	3.6	4.2	3.5	3.8
Primary energy consumption per GDP[*3]	985	702	544	543	493	418	378	-1.2	-1.1	-1.6	-1.0	-1.2
CO_2 emissions per GDP[*2, *4]	995	670	824	1,172	1,151	993	937	2.7	-0.2	-1.5	-0.6	-0.8
CO_2 per primary energy consumption[*2, *5]	1.0	1.0	1.5	2.2	2.3	2.4	2.5	4.0	0.9	0.2	0.4	0.5
Automobile ownership (million)	0.2	0.2	0.4	1.3	2.4	5.2	8.8	8.5	7.1	7.9	5.4	6.8
Automobile ownership rates[*6]	4.0	3.6	4.8	15	26	52	86	7.0	6.2	7.3	5.2	6.2

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million,
*4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

4. Indonesia

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	56	99	155	209	301	413	547	100	100	100	3.6	4.1	3.2	2.8	3.4
Coal	0.2	3.5	12	31	65	101	149	3.6	15	27	11.0	8.4	4.5	4.0	5.5
Oil	20	33	58	73	100	131	168	34	35	31	3.8	3.6	2.7	2.5	2.9
Natural gas	4.9	16	27	35	50	67	91	16	17	17	3.8	4.2	3.0	3.0	3.4
Nuclear	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Hydro	0.1	0.5	0.9	1.1	1.2	1.4	1.5	0.5	0.5	0.3	3.8	1.2	1.3	0.7	1.1
Geothermal	-	1.9	8.4	16	24	41	58	2.0	7.7	11	10.6	4.3	5.6	3.6	4.5
Solar, wind, etc.	-	-	-	0.0	0.0	0.0	0.0	-	0.0	0.0	n.a.	28.0	6.5	12.8	15.0
Biomass and waste	30	43	49	53	61	72	80	44	25	15	0.9	1.6	1.7	1.0	1.4

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	50	80	120	158	222	298	388	100	100	100	3.3	3.8	3.0	2.7	3.1
By sector															
Industry	6.7	18	31	45	73	102	135	23	28	35	4.4	5.6	3.4	2.8	3.9
Transport	6.0	11	22	39	62	92	126	13	25	32	6.4	5.2	4.1	3.2	4.1
Buildings, etc.	36	44	58	64	77	92	113	55	41	29	1.9	1.9	1.8	2.0	1.9
Non-energy use	1.2	7.4	9.8	9.8	10	12	14	9.2	6.2	3.7	1.4	0.4	1.7	1.8	1.3
By energy															
Coal	0.1	2.1	4.7	11	27	37	47	2.7	7.1	12	8.2	10.1	3.3	2.5	5.1
Oil	17	27	49	64	89	121	158	34	41	41	4.2	3.7	3.1	2.7	3.2
Natural gas	2.4	6.0	12	17	21	30	42	7.5	11	11	5.0	2.8	3.6	3.2	3.2
Electricity	0.6	2.4	6.8	14	24	38	61	3.0	8.7	16	8.6	6.2	4.9	4.8	5.3
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	29	42	48	52	61	72	80	53	33	21	1.0	1.7	1.7	1.0	1.5

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	7.5	33	93	182	310	498	788	100	100	100	8.5	6.1	4.9	4.7	5.2
Coal	-	9.8	34	81	154	276	472	30	44	60	10.6	7.4	6.0	5.5	6.3
Oil	6.2	15	18	42	39	37	34	47	23	4.3	5.0	-0.8	-0.7	-0.7	-0.7
Natural gas	-	0.7	26	37	75	122	197	2.2	20	25	20.5	8.2	4.9	4.9	5.9
Nuclear	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Hydro	1.3	5.7	10	12	14	16	17	17	6.8	2.1	3.8	1.2	1.3	0.7	1.1
Geothermal	-	1.1	4.9	9.4	27	47	67	3.4	5.1	8.5	10.6	12.6	5.6	3.6	7.0
Other renewables	-	-	0.0	0.2	0.4	0.7	1.0	-	0.1	0.1	n.a.	8.9	4.9	4.1	5.9

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	152	281	425	754	1,296	2,102	3,182	4.8	6.2	5.0	4.2	5.1
Population (million)	151	184	213	242	268	292	309	1.3	1.1	0.9	0.6	0.8
CO_2 emissions[*2] (Mt)	71	134	262	402	655	927	1,279	5.4	5.6	3.5	3.3	4.1
GDP per capita ($2010 thousand)	1.0	1.5	2.0	3.1	4.8	7.2	10	3.4	5.0	4.1	3.6	4.2
Primary energy consump. per capita (toe)	0.4	0.5	0.7	0.9	1.1	1.4	1.8	2.3	3.0	2.3	2.2	2.5
Primary energy consumption per GDP[*3]	368	351	364	277	232	197	172	-1.1	-1.9	-1.7	-1.3	-1.6
CO_2 emissions per GDP[*2, *4]	472	476	616	533	506	441	402	0.5	-0.6	-1.4	-0.9	-1.0
CO_2 per primary energy consumption[*2, *5]	1.3	1.4	1.7	1.9	2.2	2.2	2.3	1.7	1.4	0.3	0.4	0.7
Automobile ownership (million)	1.3	2.8	5.4	17	29	48	74	8.9	6.3	5.1	4.5	5.2
Automobile ownership rates[*6]	8.6	15	25	69	108	163	239	7.5	5.1	4.2	3.9	4.4

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million,
*4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

5. Philippines

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	22	29	40	40	49	66	87	100	100	100	1.7	2.3	2.9	2.8	2.7
Coal	0.5	1.4	5.0	8.4	11	17	24	5.0	21	27	8.8	3.4	3.9	3.5	3.6
Oil	10	11	16	12	17	23	32	38	31	37	0.6	3.5	3.3	3.3	3.4
Natural gas	-	-	0.0	3.3	5.4	8.5	12	-	8.1	14	n.a.	5.6	4.6	3.8	4.6
Nuclear	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Hydro	0.3	0.5	0.7	0.8	1.0	1.2	1.3	1.8	2.1	1.5	2.3	2.0	1.9	0.7	1.5
Geothermal	1.8	4.7	10.0	8.5	9.2	9.9	11	16	21	12	2.9	0.8	0.8	0.7	0.8
Solar, wind, etc.	-	-	-	0.0	0.0	0.0	0.1	-	0.0	0.1	n.a.	13.3	4.0	7.2	7.9
Biomass and waste	9.4	11	8.1	6.9	5.6	6.1	6.5	39	17	7.4	-2.2	-2.4	0.9	0.6	-0.2

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	17	20	24	24	31	42	56	100	100	100	0.9	2.9	3.1	3.0	3.0
By sector															
Industry	3.4	4.6	5.3	6.5	8.3	11	15	23	27	27	1.6	2.8	3.1	2.8	2.9
Transport	3.5	4.5	8.1	8.0	12	17	25	23	34	45	2.7	4.3	4.1	3.7	4.0
Buildings, etc.	9.4	10	10	9.0	10	13	15	52	38	27	-0.6	1.5	1.9	1.9	1.8
Non-energy use	0.3	0.4	0.4	0.2	0.3	0.3	0.3	2.0	0.9	0.6	-2.8	4.5	0.0	-0.1	1.4
By energy															
Coal	0.2	0.8	0.9	2.0	2.2	2.7	3.2	3.8	8.5	5.8	4.8	1.0	1.9	1.9	1.6
Oil	7.0	8.1	13	11	15	22	30	41	48	55	1.6	3.5	3.5	3.5	3.5
Natural gas	-	-	-	0.1	0.7	1.4	2.1	-	0.3	3.8	n.a.	27.8	7.1	4.1	12.1
Electricity	1.5	1.8	3.1	4.8	6.9	9.9	14	9.2	20	24	4.7	4.0	3.7	3.2	3.6
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	7.8	9.1	6.9	5.5	5.5	6.0	6.3	46	23	11	-2.4	-0.1	0.9	0.5	0.4

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	18	26	45	69	95	137	188	100	100	100	4.7	3.6	3.7	3.2	3.5
Coal	0.2	1.9	17	25	39	61	89	7.3	37	48	13.0	4.9	4.6	3.9	4.4
Oil	12	12	9.2	3.4	3.4	3.4	3.4	47	4.9	1.8	-6.0	0.0	0.0	0.0	0.0
Natural gas	-	-	0.0	21	30	46	66	-	30	35	n.a.	4.4	4.3	3.7	4.1
Nuclear	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Hydro	3.5	6.1	7.8	9.7	12	14	15	23	14	8.0	2.3	2.0	1.9	0.7	1.5
Geothermal	2.1	5.5	12	9.9	11	12	12	21	14	6.6	2.9	0.8	0.8	0.7	0.8
Other renewables	-	0.4	-	0.2	0.5	0.8	1.4	1.6	0.3	0.7	-3.5	10.9	4.4	5.6	6.8

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	80	95	125	207	332	526	787	3.8	5.4	4.7	4.1	4.7
Population (million)	47	62	77	95	110	128	143	2.1	1.7	1.5	1.2	1.4
CO_2 emissions[*2] (Mt)	33	38	68	78	108	157	221	3.6	3.7	3.7	3.5	3.6
GDP per capita ($2010 thousand)	1.7	1.5	1.6	2.2	3.0	4.1	5.5	1.7	3.7	3.2	2.9	3.2
Primary energy consump. per capita (toe)	0.5	0.5	0.5	0.4	0.4	0.5	0.6	-0.4	0.6	1.4	1.6	1.2
Primary energy consumption per GDP[*3]	280	303	318	195	149	125	110	-2.1	-3.0	-1.7	-1.3	-2.0
CO_2 emissions per GDP[*2, *4]	414	397	541	379	326	298	280	-0.2	-1.7	-0.9	-0.6	-1.0
CO_2 per primary energy consumption[*2, *5]	1.5	1.3	1.7	1.9	2.2	2.4	2.5	1.9	1.4	0.8	0.7	0.9
Automobile ownership (million)	0.9	1.2	2.4	3.2	5.4	8.2	12	4.7	5.9	4.3	3.9	4.7
Automobile ownership rates[*6]	18	20	31	34	49	65	84	2.6	4.2	2.8	2.7	3.2

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million,
*4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

6. Thailand

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	22	42	72	119	158	205	263	100	100	100	5.1	3.2	2.6	2.5	2.8
Coal	0.5	3.8	7.7	18	24	32	42	9.1	15	16	7.7	3.0	2.9	2.9	2.9
Oil	11	18	32	47	68	78	88	43	39	33	4.7	4.2	1.3	1.2	2.2
Natural gas	-	5.0	17	31	43	67	100	12	26	38	9.0	3.8	4.5	4.1	4.1
Nuclear	-	-	-	-	-	0.2	0.7	-	-	0.3	n.a.	n.a.	n.a.	11.6	n.a.
Hydro	0.1	0.4	0.5	0.7	0.8	0.8	0.8	1.0	0.6	0.3	2.4	1.0	0.9	0.0	0.6
Geothermal	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8	5.5	3.5	9.0
Solar, wind, etc.	-	-	-	0.0	0.1	0.2	0.5	-	0.0	0.2	n.a.	28.1	6.5	12.7	15.0
Biomass and waste	11	15	15	22	20	24	28	35	18	11	1.9	-1.0	2.0	1.5	0.9

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	15	29	51	88	116	147	184	100	100	100	5.5	3.1	2.4	2.3	2.6
By sector															
Industry	4.0	8.7	17	27	35	51	72	30	31	39	5.6	2.8	4.0	3.5	3.4
Transport	3.2	9.0	15	21	25	28	31	31	23	17	4.0	2.2	0.9	1.1	1.4
Buildings, etc.	7.8	11	14	21	25	32	41	37	23	22	3.1	2.3	2.5	2.4	2.4
Non-energy use	0.2	0.4	5.6	20	31	36	40	1.5	23	22	20.1	5.0	1.4	1.2	2.4
By energy															
Coal	0.1	1.3	3.5	9.4	11	14	17	4.5	11	9.1	9.8	2.2	2.0	1.9	2.0
Oil	7.3	15	29	46	60	68	78	52	52	42	5.5	2.8	1.4	1.3	1.8
Natural gas	-	0.1	1.1	5.8	8.4	16	27	0.5	6.6	15	19.5	4.2	6.7	5.3	5.4
Electricity	1.1	3.3	7.6	13	19	28	40	11	14	22	6.7	4.3	4.2	3.6	4.0
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	6.7	9.2	9.4	14	18	20	22	32	16	12	2.1	2.6	1.2	1.0	1.5

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	14	44	96	156	217	324	476	100	100	100	6.2	3.7	4.1	3.9	3.9
Coal	1.4	11	18	35	48	70	99	25	22	21	5.6	3.7	3.7	3.6	3.7
Oil	12	10	10	2.1	2.9	4.1	5.9	23	1.3	1.2	-7.4	3.7	3.7	3.6	3.7
Natural gas	-	18	62	107	148	214	304	40	68	64	8.9	3.7	3.7	3.6	3.7
Nuclear	-	-	-	-	-	9.8	29	-	-	6.2	n.a.	n.a.	n.a.	11.6	n.a.
Hydro	1.3	5.0	6.0	8.2	8.9	9.7	9.7	11	5.2	2.0	2.4	1.0	0.9	0.0	0.6
Geothermal	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8	5.5	3.5	9.0
Other renewables	-	-	0.5	4.4	8.1	16	27	-	2.8	5.7	n.a.	7.0	7.3	5.1	6.5

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	63	135	209	319	485	697	937	4.2	4.8	3.7	3.0	3.8
Population (million)	47	57	63	70	71	71	68	0.9	0.2	0.0	-0.3	-0.1
CO_2 emissions[*2] (Mt)	34	81	152	228	310	412	549	5.1	3.5	2.9	2.9	3.1
GDP per capita ($2010 thousand)	1.3	2.4	3.3	4.6	6.8	9.9	14	3.2	4.5	3.7	3.3	3.8
Primary energy consump. per capita (toe)	0.5	0.7	1.1	1.7	2.2	2.9	3.8	4.1	2.9	2.7	2.9	2.8
Primary energy consumption per GDP[*3]	347	311	346	373	325	294	280	0.9	-1.5	-1.0	-0.5	-1.0
CO_2 emissions per GDP[*2, *4]	537	598	727	713	639	592	586	0.8	-1.2	-0.8	-0.1	-0.7
CO_2 per primary energy consumption[*2, *5]	1.5	1.9	2.1	1.9	2.0	2.0	2.1	0.0	0.3	0.2	0.4	0.3
Automobile ownership (million)	0.9	2.8	6.1	11	15	18	20	6.9	2.7	2.0	1.4	2.0
Automobile ownership rates[*6]	19	49	97	164	205	250	297	5.9	2.5	2.0	1.7	2.1

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million,
*4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

7. Malaysia

Primary energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total[*1]	12	22	47	76	102	129	152	100	100	100	6.2	3.3	2.4	1.6	2.4
Coal	0.1	1.4	2.3	16	19	29	36	6.3	21	24	12.3	2.4	4.0	2.5	3.0
Oil	7.9	11	19	28	34	37	40	53	36	26	4.3	2.3	1.0	0.6	1.3
Natural gas	2.0	6.1	22	28	45	55	61	28	38	40	7.6	5.2	2.1	1.0	2.7
Nuclear	-	-	-	-	-	2.6	7.7	-	-	5.1	n.a.	n.a.	n.a.	11.6	n.a.
Hydro	0.1	0.3	0.6	0.7	0.7	0.9	1.0	1.6	0.9	0.7	3.1	0.0	3.4	1.1	1.5
Geothermal	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Solar, wind, etc.	-	-	-	-	0.0	0.0	0.0	-	-	0.0	n.a.	n.a.	6.5	12.8	n.a.
Biomass and waste	1.8	2.4	2.9	3.5	3.2	4.5	5.7	11	4.6	3.8	1.8	-0.9	3.3	2.5	1.7

Final energy consumption	Mtoe							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	7.3	14	30	45	65	81	95	100	100	100	5.7	4.1	2.2	1.6	2.6
By sector															
Industry	3.1	5.6	12	12	20	27	34	40	26	36	3.6	6.0	3.3	2.1	3.7
Transport	2.1	4.8	10	14	19	21	23	34	32	24	5.4	3.2	1.2	0.8	1.6
Buildings, etc.	1.7	2.8	5.4	9.6	14	19	24	20	21	26	6.0	4.2	3.1	2.5	3.2
Non-energy use	0.3	0.8	2.1	9.1	12	13	14	5.6	20	14	12.4	2.8	1.0	0.5	1.4
By energy															
Coal	0.1	0.5	1.0	1.8	1.8	2.2	2.5	3.7	3.9	2.6	6.0	0.1	2.2	1.1	1.2
Oil	5.3	9.2	18	24	31	34	36	66	54	38	4.8	2.7	0.9	0.6	1.4
Natural gas	0.0	1.0	3.5	7.7	15	20	23	7.1	17	24	10.3	7.8	2.6	1.6	3.8
Electricity	0.7	1.7	5.3	9.2	14	22	29	12	21	31	8.4	5.0	4.3	3.0	4.1
Heat	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Renewables	1.2	1.5	1.8	1.8	2.3	3.0	3.6	11	3.9	3.8	0.6	3.1	2.6	1.9	2.5

Electricity generation	(TWh)							Shares (%)			CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990	2011	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
Total	10	23	69	130	201	298	387	100	100	100	8.6	5.0	4.0	2.7	3.8
Coal	-	2.9	7.7	53	74	116	155	13	41	40	14.8	3.8	4.6	3.0	3.8
Oil	8.5	11	3.6	10.0	10.0	10.0	10.0	48	7.7	2.6	-0.5	0.0	0.0	0.0	0.0
Natural gas	0.1	5.0	51	58	106	146	173	22	45	45	12.4	6.9	3.2	1.7	3.8
Nuclear	-	-	-	-	-	9.8	29	-	-	7.6	n.a.	n.a.	n.a.	11.6	n.a.
Hydro	1.4	4.0	7.0	7.6	8.1	11	13	17	5.9	3.3	3.1	0.7	3.4	1.1	1.8
Geothermal	-	-	-	-	-	-	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Other renewables	-	-	-	1.3	2.9	4.6	6.8	-	1.0	1.8	n.a.	8.8	4.9	3.9	5.7

Energy and economic indicators								CAGR (%)				
	1980	1990	2000	2011	2020	2030	2040	1990/ 2011	2011/ 2020	2020/ 2030	2030/ 2040	2011/ 2040
GDP ($2010 billion)	43	76	151	250	392	611	845	5.8	5.1	4.5	3.3	4.3
Population (million)	14	18	23	29	33	37	40	2.2	1.5	1.2	0.8	1.1
CO_2 emissions[*2] (Mt)	28	53	115	188	253	321	372	6.3	3.4	2.4	1.5	2.4
GDP per capita ($2010 thousand)	3.1	4.2	6.5	8.7	12	17	21	3.5	3.6	3.3	2.5	3.1
Primary energy consump. per capita (toe)	0.9	1.2	2.0	2.6	3.1	3.5	3.8	3.9	1.8	1.2	0.8	1.3
Primary energy consumption per GDP[*3]	279	283	311	304	260	211	179	0.3	-1.7	-2.1	-1.6	-1.8
CO_2 emissions per GDP[*2, *4]	663	690	756	752	646	526	440	0.4	-1.7	-2.0	-1.8	-1.8
CO_2 per primary energy consumption[*2, *5]	2.4	2.4	2.4	2.5	2.5	2.5	2.5	0.1	0.0	0.0	-0.2	0.0
Automobile ownership (million)	0.9	2.4	5.2	11	14	16	18	7.4	2.9	1.6	0.9	1.7
Automobile ownership rates[*6]	65	133	224	376	427	445	449	5.1	1.4	0.4	0.1	0.6

*1 Trade of electricity and heat are not shown, *2 Excludes emission reduction by CCS, *3 toe/$2010 million, *4 t/$2010 million, *5 t/toe, *6 Vehicles per 1,000 people

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