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Published in Energy Policy 37 (2009) 1601–1613,
doi::10.1016/j.enpol.2008.12.026

Economic Potential of Renewable Energy in Vietnam's Power Sector

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Abstract

A bottom-up Integrated Resource Planning model is used to examine the economic potential of renewable energy in Vietnam's power sector. In a baseline scenario without renewables, coal provides 44% of electricity generated from 2010 to 2030. The use of renewables could reduce that figure to 39%, as well as decrease the sector's cumulative emission of CO_2 by 8%, SO_2 by 3%, and NO_X by 4%. In addition, renewables could avoid installing 4.4 GW in fossil fuel generating capacity, conserve domestic coal, decrease coal and gases imports, improving energy independence and security. Wind could become cost-competitive assuming high but plausible on fossil fuel prices, if the cost of the technology falls to 900 US$/kW.

Key words: integrated resource planning, renewable energy, electricity generation

1. Introduction

The transformation to a mostly market-driven economy has led Vietnam to faster economic growth with annual rates of 7-8% during the last decade. The need for electricity services in Vietnam has been increasing in parallel with industrial development, migration of people to cities, and rising living standards. As discussed by Nguyen and Tran (2005), and Khanh, Q. Nguyen (2007b), given the high growth of electricity generation in Vietnam, thermal power generation is likely to increase in the years to come. Coal is expected to be the dominant fuel for electricity generation from 2015 to 2030. As a result, the share of CO_2 emission coming from the power sector in the national CO_2 emission inventory is expected to grow. Yet increasing the use of fossil fuels to meet growing worldwide demand for electricity, especially in developing countries, goes against the need to prevent dangerous climate change globally, and has detrimental health and environmental effects locally.

There is an extensive literature on how to mitigate emissions by using different combinations of primary energy resources to generate electricity in Asia. Chattopadhyay, D. (1994) analyzed some mitigation options such as switching cleaner fuels (i.e. from coal to natural gas) to reduce CO_2 emissions in India's power sector. Fernando et al. (1994) developed an integrated resource planning approach considering both supply and demand side options to address the twin problems of environmental degradation and capital costs in developing countries. Benjamin, F. Hobbs (1995) examined how environmental concerns, increased competition, and growing uncertainty have changed the needs of utility planners for optimization models and surveyed a range of models for electric utility resource planning that have developed in response to those needs. Swisher et al. (1997) assembled all necessary information addressing tools and methods for integrated resource planning to improve energy efficiency and protect the environment. Shrestha et al. (1998) developed the integrated resource planning (IRP) model to address the implications of a carbon tax and technological constraints in a developing country. Shrestha and Marpaung (1999) analyzed alternatives for reduction of greenhouse gases from Indonesian electric power generation by integrating supply- and demand-side options in an electric utility planning considering the effects of carbon tax. Shrestha and Marpaung (2002) examined the implications of CO_2 emission targets in Indonesian power sector using the IRP analysis. Somporn et al. (2004) applied the IRP model to examine the effects of both supply and demand side options on the CO_2 mitigation potential from the power sector in Thailand.

Subhes C. B., and Dang, N.Q. Thang (2004) examined the cogeneration potential of the sugar industry to meet the increasing electricity demand in Vietnam based on avoided cost ground under the IRP framework, Khanh, Q. Nguyen (2007a, 2007b) estimated the potential of wind energy using a geographical information system assisted approach and used the MARKAL, a least cost model, to simulate the impacts of wind power generation and CO_2 emission constraints on the future choice of fuels and technologies in Vietnam's power sector. All of these studies suggest that integrating renewable energy sources in a cost-effective way is a necessary answer to the energy/environment dilemma.

This paper attempts to give new insights about what it is possible to do in terms of generating electricity and reducing carbon emissions in Vietnam. The originality of this study is to explore the potential of all renewable energy sources together for electricity generation in Vietnam. To this end, using the IRP model we analyze the optimized integration of a large array of grid-connected renewable energy technologies, i.e. hydro, geothermal, biomass, wind, solar,…,etc., in the power electric generation system to meet the challenges of soaring electricity demand, growing environmental concerns, energy pricing climax, and energy security over the period 2010-2030.

The next section summarizes the development of Vietnam's power sector from 1995 to 2005 and official projections out to 2030. It also summarizes quantitatively the national potential of renewable energy sources for electricity generation. Section 3 presents the IRP model and the two scenarios to be compared: with and without renewables. Results discussed in section 4 examine the extent to which renewables can substitute for coal in the optimal generation mix through 2030, and the economic and environmental benefits of such substitution. Section 5 presents a sensitivity analysis based on electricity demand forecast scenarios, the availability of fuels/electricity sources, trends of fossil fuel prices, and costs of renewable energy technologies. Some policy implications are then proposed for the electric power-generation expansion plan in Vietnam. Section 6 concludes.

2. The power sector and renewables in Vietnam: status and perspectives

Electricity generation, transmission and distribution in Vietnam are mostly provided by Electricity of Vietnam (EVN), a state-owned monopoly established in October 1994 under the Ministry of Industry. At the end of 2005, the total electricity-generation capacity was 11,340 MW, of which Electricity of Vietnam facilities accounted for approximately 78%. The remainder was owned by other local and foreign Independent Power Producers.

The current electricity generation system in Vietnam consists of thermal gas-based power plants (39%), hydropower plants (37%), and thermal coal; this last now accounts for approximately 16% of electricity generation, and it will play an increasingly important role in the medium and long term. Transmission and distribution loss in Vietnam remains high, even if it has been significantly reduced from 22% in 1995 to 12% in 2005. EVN has developed a plan to reduce transmission and distribution losses to less than 8% by 2025 (Electricity of Vietnam, 2006a, 2006b).

The development of the electric power sector in Vietnam is managed using the Power Development Master Plan, which estimates the need for electricity and plans the overall development of the power sector during a 10-year period, taking into account the subsequent 10-year period. The current Sixth Power Development Master Plan was approved by the Prime Minister in July 2007. It projects that an additional capacity of more than 10,000 MW will be required between 2005 and 2010 to meet the rapidly growing demand for electricity services. Figure 1 maps the distribution of electricity-generation sources in Vietnam planned for 2010.

Figure 2 presents the historical and forecasted need for electricity energy in Vietnam since 1990, when the Vietnamese Government launched a comprehensive reform. This reform has helped to improve people's living conditions and has driven the development of the national economy. Gross domestic production (GDP) in Vietnam has experienced a rapid growth rate of 8.2% per annum during 1991-1995. The strong economic growth is the main reason that electricity demand has increased by 13.5% over the same period. Demand then grew faster, by 14%, over the period 1995-2005, together with economic development. The Sixth Master Plan was formulated based on scenarios for development of different economic sectors and regions and a comparative analysis using the three forecasting methods of multiple regression, elasticity and intensity. According to this Plan, the electricity demand is expected to increase by 15% per annum in the low-demand scenario and by 18% per annum in the high-demand scenario over the period of 2010-2030.

Renewable energy potentials are commonly classified in different categories of theoretical, technical, and economic potential. Theoretical potential is defined at the maximum energy that could be exploited in a region considering only thermodynamic constraints. Technical potential is defined by the energy that could be yielded using existing technology, and thus depends on the date of assessment. Economic potential is defined by the energy that could be yielded using economically feasible installations. Infrastructure or technical constraints and economic aspects (costs of alternative competitive energy sources) determine the limits of the economic potential (Voivontas et al., 1998). Table 1 shows that Vietnam has lots of renewable energy sources that are not yet fully exploited.

Hydro energy: Vietnam has 2 400 rivers 10 km or longer. The hydro energy economic potential is estimated at 84 TWh/yr, which is more than the electricity consumption of 46 TWh in 2005.

Hydro pump storage energy: Vietnam's economic potential is over 10,000 MW of hydro pump capacity. These resources are mainly located in the northern and southern areas of the country.

Geothermal energy: With more than 300 hot streams from 30 °C to 148 °C, Vietnam is preliminarily estimated to have 1, 400 MW that could be developed for direct use and producing electricity. In which, 400 MW geothermal capacity could be developed for producing electricity up to 2020.

Biomass energy: Biomass resources that could be used for generating electricity include rice husk, paddy straw, bagasse (sugar cane, coffee husk, and coconut shell), and wood and plant residue with a potential of 1000-1600 MW.

Solar energy: Vietnam lies from 23° to 8° North latitude and has good constant solar sources. In the southern and central areas, solar radiation levels range from 4 to 5.9 $kWh/m^2/day$ uniformly distributed throughout the year. The solar energy in the north estimated to vary from 2.4 to 5.6 $kWh/m^2/day$.

Wind energy: Vietnam has approximately 513 GW of theoretical capacity. Excluding restrictions on the exploitation of the potential, 120.5 GW of wind power capacity, about 10 times the peak load demand in 2005 is estimated economically feasible for producing electricity.

In what follows, we examine the economic potential of renewables, assuming that no barriers to the adoption of these renewable energy technologies and that they are used optimally from a lowest-cost perspective. We use the integrated resource planning (IRP) model to compare two optimized plans for expanding electricity generation in Vietnam, one with and the other without renewables. To this end, sensitivity analysis is performed to seek greater energy independence and energy security by integrating diverse energy sources and to response the questions of at what conditions would the renewables become cost-competitive with fossil options in Vietnam.

3. The Integrated Resource Planning (IRP) model

Most developing countries face the chronic problem of insufficient financial resources for developing their electric power sector because such development requires huge capital investments. Ineffective exploitation and use of limited domestic energy resources usually leads to electric power supply shortages, creating the need to import fuel or electricity, which puts a major drain on foreign exchange reserves. Moreover, climate change and public health problems can further complicate the development of the power sector in these countries. The United Nations Conference on Environment and Development agreed in June 1992 that all countries should adopt necessary adequate programs to restrain increases in greenhouse gas emissions. This restraint is an environmental hindrance to the development of the power sector in many developing countries.

To address these challenges, energy planners use optimization methods for electric utility resource planning, which is the selection of power generation and energy efficiency resources not only to meet the increasing need for electricity services with cost-effective reductions in the use of electricity, but also lessen the impacts associated with electricity generation. Shrestha and Nguyen (2003) presents the integrated resource planning (IRP) model, which was developed in 1998 by the Energy Program of the School of Environment and Resources Development of the Asian Institute of Technology. It uses mixed-integer linear programming (MILP) to compute a lowest-cost electricity-generation capacity expansion plan. The objective function of the IRP model is to compute the least cost combination of generation capacities of different generation sources, the level of end-use electrical appliances to be added (i.e. demand side), and the level of electricity generated by different plants subject to the following constraints:

(i) Demand constraint: the total power generation by all power plants (existing and future) and generation avoided by demand-side management options should not be less than the total projected power demand in all periods (blocks)[1], seasons, and years of the planning horizon.

(ii) Plant availability constraint: the power generation of each plant is limited to the capacity and availability of the plant during each period of the day.

[1] The daily chronological load curve in the model is divided into several blocks (i.e. time intervals) in order to adequately reflect the effects of variations in power demand over various periods of a day

(iii) Reliability constraint: the total power generation capacity of all the plants and generation capacity avoided by demand-side management options must not be less than the sum of the peak power demand and the reserve margin in each year of the planning horizon.

(iv) Annual energy constraint: a maximum limit is set on the energy generation at each plant based on its existing capacity, availability, and maintenance schedule.

(v) Hydro energy availability constraint: the total energy output of each hydro plant in each season should not exceed the plant's maximum available quantity of hydro energy.

(vi) Maximum potential capacity constraint: total installed capacity of each type of power plant must not exceed the maximum allowable capacity of that plant type.

(vii) Minimum operation capacity constraint: all selected thermal generating units, depending on their characteristics (off-peak, intermediate, peak plants…,etc.) must be operated and dispatched to generate electricity energy production at a certain minimum business running capacity, at least.

(viii) Fuel or resource availability constraint: energy generation from a plant cannot exceed the maximum available quantity of fuel supply resources.

(ix) External power availability constraint: energy generation imported cannot exceed the maximum available quantity of external power generation resources.

(x) Demand side management constraint: the level of energy-efficient device selected in a year must not exceed the maximum feasible level of such device in the year.

We consider 14 alternative generation technologies and 10 kinds of fuels. Table 2 summarizes the technical, economic, and environmental characteristics of these generation technologies. The renewable energy generation technologies (RET) considered are: small and mini hydro, geothermal, wind turbine, solar grid connected, biomass-based integrated gasification combined cycle, and biomass direct combustion. Table 3 displays the fuel prices used in the model. Price escalation is defined as the total annual rate of increase in a cost, including the effects of both inflation and real escalation. We assumed that the fuel prices could increase 1-2 percent per year. All energy prices based 2005 and their escalation rates were estimated by Institute of Energy, 2006c. These were used to prepare and evaluate nuclear power development plan in Vietnam and are relatively moderate compared to the market levels observed in early 2008. We, however, carried out a sensitivity analysis, using higher levels of energy prices for more precisely estimation of renewables generation potential compared to fossil fuels options.

Through IRP simulation, 2 seasons (rainy and dry) are modeled in a year. The load curve in a day of a season is divided into 24 blocks (1 hour/block). Renewable energies (such as wind, solar, and small hydro) generation is modeled correlatively to its intermittent nature. In the IRP, plant dispatch is modeled under merit order method and the readiness of generating electricity from renewable plants depends on their energy source availability, i.e. generation of wind/solar technology depended on the available level of wind, sunlight in each block of a day, and that of small hydro depended on the water level in each season. In this study, the economic potential of renewable energy and its implications for the development of electric power generation in Vietnam are analyzed by comparing a model run without renewables against a model run with renewables. The two scenarios will be named “B1” and “B2”. The B1 scenario assumes that the power sector in Vietnam for a period of 2010-2030 will not develop any renewable energy sources, except for large hydro and hydro pump storage. The B2 scenario assumes that during the same period, all of the economically possible RETs mentioned above will be considered for sustainable development of electric power generation in Vietnam. In all other respects, the scenarios are identical. Both scenarios assume the adoption of highly energy-efficient thermal technologies such as supercritical and IGCC coal-fired plants, NGCC gas-fired plants and they assume that there are no direct climate change policy interventions. The same average predicted load demand, transmission and distribution losses, and electricity consumed in each period (see Table 4) are applied to both scenarios. Furthermore, both assume that nuclear energy and demand-side management are not used.

To meet the rapid increase in electricity demand forecast for 2010-2030, Vietnamese organizations are considering different economic alternatives for expanding the electricity-generation system. Fuels considered economically viable for producing electricity are domestic fossil fuel resources and imports, including imported electricity. The availability of domestic fuels supply is based on exploiting estimation scenarios of natural gas and coal-mining industries locally. The possibilities for importing fuel or electricity sources have been estimated depending on their availability and national financial resources. The electricity import is mainly from hydro sources via ASEAN power interconnection system projects that have been concurred or negotiating with neighbor countries such as China, Lao, and Cambodia. The success of these projects depends on involved countries' economic development, impacts of international market pricing level, national strategy on bilateral and multilateral cooperation, etc.... The Vietnamese Government agencies, however, have also carried out an overall assessment of the feasibility of importing electricity and its purchasing prices from these projects (Institute of Energy, 2006c). In the model, the electricity imports are simulated by different hydro generation sources with purchasing electricity prices varied from 4.3 to 4.9 $cent/kWh. Table 5 indicates the maximum quantity of domestic fuels supply and imports (fuels/electricity) for baseline scenarios and sensitivity analysis.

The scenarios applied in this study coincide with the baseline forecast and estimates from official Vietnamese Government agencies. These predictions, however, include very few renewables.

4. Results

Since IRP is a bottom-up optimization model, optimizing over a broader technology portfolio can improve results. Thus, it is no surprise that the B2 run (with renewables) performs better economically than the B1 run (without renewables). More interesting, perhaps, are the quantitative differences between the two scenarios, which are summarized in Tables 6 and 7 and discussed in more detail below. We examine in turn the implications for electricity planning, the benefits of using renewables from the perspective of domestic energy security, the cost improvements, and the environmental benefits.

Overall, IRP simulation suggests that 4.4 GW could be obtained from renewable energy sources in a cost-effective manner for the production of electricity in Vietnam. Small hydro and geothermal energy account for 45.5% and 31.8% of this quantity, respectively. The rest comes from biomass energy (bagasse, rice husk, and paddy straw).

Implications for Electricity Planning: How could the combination of diversified energy sources, including unconventional energy sources, enable the expansion of electric power generation in Vietnam? IRP results indicate how the addition of electricity-generating capacity and the diversification of electricity sources could be technologically achieved during the specified period. Compared to the B1 scenario, the more cost-effective combination of energy resources in the B2 scenario reduces the total amount of electricity generated by conventional thermal plants. The IRP simulation suggests that electricity generation based on coal-fired plants can be reduced from 43.6% to 39%, and gas-fired plants reduced from 32.4% to 32.1%. This change is primarily due to the fact that RETs can compete more effectively against traditional electricity sources in terms of cost. The electricity generation based on oil-fired plants would be kept unchanged in both scenarios B1 and B2. This is because no new oil-fired plants would be cost-effective selected and all the existing ones are continuously operated as reserve or peak generating units in the system to provide with a certain level of electricity generation in both scenarios.

Introducing RETs into the electric power-generation system could help the country to avoid installing 4.4 GW in fossil fuel generating capacity. This is because RETs offer the supply-side option of unit sizes of various capacities with low or zero fuel cost. Both advantages could make RETs more cost-effective than other technologies in responding to variations in demand for electric power at different times.

Renewables based capacity is a good but not perfect substitute for fuel-based capacity. The B2 scenario requires an increase of 232 MW in additional total generation capacity. This extract capacity allows, in the B2 case, to use less the least efficient generating plants. As a result, compounding renewable energy sources with conventional sources increases total average thermal efficiency from 46.7% in the B1 scenario to 47.2% in the B2 scenario. It also decreases the weighted average capacity factor[2] from 64.7% in the B1 scenario to 64.4% in the B2 scenario. This shows that generation units that are more energy-efficient can be more effectively utilized and some generation units that are less efficient can be relied upon less or even replaced completely. More geothermal grid-connected generation units with very high thermal energy efficiency could help significantly improve the overall average thermal system efficiency.

The total electricity generation as modeled here, which must be equal to or larger than total demand in equilibrium, is reduced by 19.5 TWh in the B2 scenario compared to the B1 scenario during the same outlook period. This is because in the IRP model all selected thermal generating plants (existing and future) are simulated with different minimum operating capacities depending on their characteristics (technologies, fuels, capacity, and off-peak, intermediate, peak operation modes,…,etc.). This simulation implies that whenever a thermal power plant is constructed, it must be dispatched to generate electricity at a certain minimum business running capacity, at least. On this simple ground, when some generating units on reserve with less efficiency but larger minimum operation capacities in scenario B1 are, in scenario B2, replaced by higher efficient units with smaller minimum operation capacities, the accumulated minimum electricity generation from those on reserve in scenario B2 could be reduced. This results in reduction in the total electricity

[2] Capacity factor of a power plant is the ratio of its actual total electricity generation during a period to the maximum potential electricity generation if it had operated at full installed capacity during same period. The weighted average capacity factor is calculated from annual capacity factors with weights being the annual shares in cumulative electricity generation during the entire planning horizon.

generation in scenario B2 accordingly, compared to scenario B1 over the whole planning period.

The second question of how the development of electric power generation integrated with such RETs can maintain the same quality level of electricity services compared to the B1 scenario is also examined. As an answer to this question, Table 7 shows an decrease in the weighted average loss of load probability (LOLP)[3] from 0.05% in the B1 scenario to 0.01% in the B2 scenario and a significant reduction in total expected energy not served (EENS)[4] from 57.7 GWh in the B1 scenario to 8.5 GWh in the B2 scenario during the specified planning period. This is because reserve capacity in the B2 scenario increases, and RET units are simulated with higher availability factors and lower unit forced outage rates.

Implications for Natural Energy Resource Conservation and Energy Security:

Figure 3 and Table 7 suggest that cost-effective renewable sources could substitute to a relatively small extent for domestic coal and natural gas. The country could save approximately 141.4 million tons of domestic coal and 1.53 billion m^3 of domestic gas for producing electricity during the specified period. Furthermore, Figure 4 indicates that the country could slightly reduce its imports: the demand for imported resources in the B2 scenario is only 304 million tons of coal, 75 billion m^3 of natural gas, and 377 TWh; compared to the B2 import demand of 311 million tons of coal, 78 billion m^3 of natural gas, and 385.6 TWh. This corresponds to savings of 1.34 billion US$ in fuel/electricity imports.

These results were obtained assuming that the prices for domestic and imported fossil fuels are moderate and have annual inflation rate relatively slowly compared to the market levels observed in recent years. Prices in 2008, for example, reached levels higher than those assumed in the study by 20-50% for coal and gas, 70-85% higher for fuel oil. The annual inflation rate of fuel prices rose from 2.3% to 3% per year (World Energy Outlook, IEA 2006).

Cost and Pricing implications:

In the IRP model, the electricity price in terms of average incremental cost (AIC) and long run average cost (LRAC) does not play any driven role to compute the optimal solution.

[3] Loss of load probability (LOLP) is the proportion of time when the available generation is expected to be unable to meet the system load. Weighted average LOLP is calculated from annual LOLP figures of the system with weights being the annual shares in cumulative electricity generation during the entire planning horizon.

[4] Expected energy not served (EENS) is the expected amount of energy not supplied during a period due to insufficient capacity.

These costs are calculated, based on the optimal solution computed for the electricity-generation capacity expansion plan using the following formulas:

$$AIC = \left(TC - C_1 - \sum_{i=1}^{T} VC_1 / (1+r)^i \right) / \left(\sum_{i=2}^{T} (E_i - E_1) / (1+r)^i \right) \quad (1)$$

$$LRAC = TC / \left(\sum_{i=1}^{T} E_i / (1+r)^i \right) \quad (2)$$

where TC = present value of total cost including capital, fuel, operation and maintenance costs; C_1 = present value of capital cost in year 1; VC_1 is the total fuel, operation and maintenance, and demand-side management costs in year 1; E_1 *and* E_i are the electricity generation in year 1 and year i; r = discount rate; and T = planning horizon.

Table 7 suggests that a reduction of 2.6% (1.3 billion US$) in the total discounted cost of electric power-generation plan could be gained by optimizing the inclusion of renewables in the mix. Figure 5 and Table 7 compare the B1 and B2 scenarios in terms of annual fuel and variable cost. Since fuel and variable cost account for 60-75% of the cost of electricity production, the lower fuel and variable costs in the B2 scenario (1.1 billion US$ lower compared to the B1 scenario) could lead to lower production costs. In addition, lower capital and fixed operation and maintenance (O&M) costs in the B2 scenario imply that some RETs in Vietnam, such as small hydro, geothermal, and biomass (except wood) could become cost-effective enough to compete against conventional sources.

The reasons of falling over time (especially during 2020-2030) in capacity and fuels costs as indicated in Figure 5 would be explained as: though the average electricity demand is estimated to increase by 15%-18%, the increasing rate of peak load demand in the period of 2020-2030 is relatively lower than that in previous years. In addition, in the IRP simulation the capacity on reserve is set to decrease gradually from 30% in year 2010 down to 0.25 over 2020-2024 and 0.2 over 2025-2030. These would be leading to reducing the additional capacity installed, i.e. capacity costs for the additions would be falling accordingly, to meet the peak load demand over the last years of the study time frame. Furthermore, over this period of 2020-2030, some of existing less efficient plants, i.e. higher fuels consumptions, would be retired and replaced by more efficient ones with lower fuels consumptions. This would result in falling fuel prices at the later part of the study period.

Integrating RETs in the development of electric power generation could not only help the country reduce the financial effect of increased demand for electricity, but it could also reduce electricity pricing in Vietnam by 0.03 $cent/kWh, in terms of average incremental cost (AIC), for the period of 2010-2030.

Environmental Implications: The IRP permits analysis of the mitigation potential of renewables with respect to emission of CO_2 and other harmful substances in the power sector in Vietnam.

Table 7 shows that the total cumulative CO_2 emission released in the B2 scenario is significantly reduced by 8% over 3825 million tons emitted in the B1 scenario for the period 2010-2030. This is an average reduction of 15 million tons of CO_2 per year during 2010-2030, which is a big fraction of the estimated 36 million tons of total CO_2 emission emitted from Vietnam's electricity-generation industry in 2006 (Nguyen and Tran, 2005). Typically for this kind of bottom-up model, the abatement cost is negative.

In addition to mitigating global emission, the country could also avoid 3% of total SO_2 and 4% of total NO_X emissions emitted during the same period. This is an average reduction of 3.9 kt of SO_2 and 11.8 kt of NO_X per year during 2010-2030, which compares to the estimated 128.2 kt of total SO_2 and 102 kt of total NO_X emitted by the sector in Vietnam in 2006 (Nguyen and Tran, 2005).

In this study, the optimization procedure did not take into account the environmental or health costs of energy sources. Including these costs would reduce the use of conventional thermal power plants, especially coal-fired plants. At the social optimum, emissions of CO_2 and other harmful substances by the electricity-generating industry in Vietnam would be reduced accordingly.

5. Sensitivity analysis and discussion

The IRP simulation suggests that some power-generating plants based on renewable technologies such as solar, wind, and biomass wood are still not cost-effective, mainly because of the high cost of these technologies. However, these costs are expected to fall over time due to technological innovation.

In this study, sensitivity analyses referred to as SA1 through SA7 were performed for:

+ quantities of fuel/electricity imported and domestic fuels supply during the period 2020-2030, based on the country's policy and availability of fuel/electricity sources (Table 5)
+ low/high load demand forecasts, which reflect greater or smaller prospects for economic development during 2020-2030 (Table 4);

+ changes in fuel prices based on market levels observed in recent years and World Energy Outlook, IEA 2006 (Table 3)
+ reductions in the renewable energy-generation technologies costs-based technological innovation evolution (Erik Ahlgren et al., 2007).

The first part of this section determines the answer to the question of at what conditions would the renewables become cost-effective with fossil options in Vietnam, and how much these could be cost-effectively generated. Table 8 shows that all assumed potential of small hydro, geothermal, and biomass technologies, except for wood energy could be economically exploited in a cost-effective manner in the scenarios. Among these RETs, small hydro has the biggest potential for producing electricity. In the B2 scenario, small hydro and geothermal could cost-effectively generate 146.5 TWh and 124.3 TWh, respectively, during 2010-2030. Biomass energy (other than from wood) could cost-effectively generate of the remaining 26.8% of the total 370 TWh generated by RETs during this period. In all scenarios of sensitivity analysis, the total electricity generated by geothermal (1400 MW) and biomass (1000 MW) over 2010-2030 would not exceed that in scenario B2. This is because the maximum potential for these two renewables to generate electricity in a cost-effective manner has been achieved. In contrast to the other RETs examined in this study, wind power, wood energy, mini hydro, and solar energies could not be cost-competitive with conventional energy sources to produce electricity at their technology costs and fossil fuel prices assumed in the B2 scenario. The following discusses what would be required to make them cost-effectively competitive.

The higher prices of fossil fuels in scenarios SA5, SA6, and SA7 could make the additional small hydro capacity potential (300 MW) become competitive in terms of cost-effectiveness, and in this case small hydro could generate a maximum of 163 TWh in a cost-effective manner. IRP simulation also suggests that mini hydro energy potential of 100 MW could become cost-effective, and that it could cost-effectively generate 4.7 GWh in the case of high fuel prices. In the combined case of high fuel prices and a forecast of high load demand, mini hydro could generate up to 4.9 GWh.

Neither wind power nor wood biomass could become cost-effective, either in the scenario of predicted high load demand or the scenario of increased fuel prices. However, if the cost of power-generation technology based on wood energy fell to approximately 1500 US$/kW (100 US$/kW lower than in the B2 scenario), it would become cost-competitive in the case of high fuel prices. Table 8 suggests that in the SA7 scenario, wood energy could provide

100 MW and 10.6 TWh effectively during the specified period. This key finding argues for investment in wood plantation-based power-generating plants in the Vietnamese power sector.

In the scenario SA6, wind power is found to be cost-effective if its technology cost falls to approximately 900 US$/kW (100 US$/kW lower than the baseline scenario) in the context of high fuel prices. Wind power capacity of 4622 MW could be installed by 2030, with a total of 240.2 TWh generated during the period 2010-2030. This implies the possibility of integrating wind power into the Vietnamese power sector in the form of Clean Development Mechanism (CDM)-funded projects.

In contrast to the other RETs, power-generation technology based on solar energy was not cost-effective in any of case studies even at a promising technological innovation cost level of 1 300 US$/kW. This simulation implies that solar energy gird-connected technology would be still expensive for cost-competitive with others in Vietnam's power sector for the next 20 years, at least.

The second part of this section focuses on argument for seeking greater energy independence and energy security by integrating diverse energy sources for generating electricity in Vietnam under assumptions of market changes in fuels prices and insufficient fossil fuels supply. The SA8 scenario examines high fossil fuel prices, constraints on imported natural gas, coal fuels and electricity, and no constraint on domestic coal fuel are coherently examined. Scenarios SA9 through SA11 look at different quantitative constraints on domestic coal fuel used for producing electricity.

When additional constraints on imports (gas and electricity), and high fossil prices introduced in SA8, reductions in imports capacities would be substituted by capacity additions of domestic coal, gas, large hydro, and renewables (small and mini hydro). IRP simulation indicates that the total 4 GW capacity potential (equals to 205 TWh in electricity generated over 2010-2030) of small and mini hydro would be dispatched to generate electricity over the specified period in this scenario. Wind power and wood biomass are still not cost-effective dispatched in this SA8 scenario because no constraint on domestic coal supply allows the power generation system to rely on low-cost coal. However, when constraints on domestic coal fuel supply are introduced additionally (SA9 through SA11), the power generation system switches away from domestic coal and electricity import towards large hydro and renewables. Table 8 suggests that both wood biomass and wind power would become cost-effective in the SA9 case, and even more in the SA10 and SA11 case.

In the conditions described under SA11, wind power (20 GW of capacity, or 162 TWh in electricity generated over 2010-2030), along with large hydro (18 GW capacity, or 1 316 TWh) and small/mini hydro (4 GW capacity, or 205 TWh) are used.

All data used in this paper are based on official documentation provided by authorized organizations in Vietnam. It seems to be optimistically estimated somehow. We, however, considered the time frame of the study by 2030, instead of 2025 for making the plan more realistic.

6. Concluding remarks

Renewable energy sources could have a minor but non negligible part in the national plan to generate electric power in Vietnam. The candidate grid-connected generation technologies include small hydro, mini hydro, geothermal, solar, wind turbine, integrated gasification cycle based on biomass (rice husk, paddy straw, wood residue), and direct combustion technologies based on biomass (bagasse). The study did not consider nuclear energy option in the analysis due to public acceptance problems related to nuclear waste disposal risks, national backward scientific standard, poor technical and technical capability, weak industrial infrastructure and regulation system, lack of human resources and professional specialists, etc. Moreover, DSM, the important option for utility electric planning, was not used in this paper in order to focus on examining the role of renewables as energy supply side option compared to fossil fuel options. However, both these options are considered in another overall research paper.

Our IRP simulations agree with Khanh, Q. Nguyen (2007b) in that regardless of whether RETs are included, the power sector in Vietnam will rely primarily on fossil fuels after 2015, especially on coal. Large quantities of CO_2 will be emitted into the atmosphere from electricity generation. The demand for electricity services over 2010-2030 may exceed the domestic fuels supply sources for generating electricity in Vietnam. The country, thus, need to import electricity energy as soon as 2010, coal and natural gas since 2015 and 2016, respectively.

More precisely, this study finds that without renewables, electricity energy generation from fossil fuels may account for 76.34% of the total production of 7389.6 TWh over the specified period. In this case, coal would account for 43.6% of the total production, while hydro would account for only 18.4%. Fossil fuel sources are the primary contributors to the increasing share of CO_2 emissions due to the power sector. The increase would be from 60.7 million tons in 2010 to 352.3 million tons in 2030, equals to a growth rate of 14% per year that will total 3825.3 million tons for the period 2010-2030.

This paper finds that some of small hydro with good hydrographic condition, geothermal, and biomass (except for wood) plants would cost competitive to fossil fuels options in Vietnam. Others with highly intermittent nature like wind, other small/mini hydro and wood biomass would only be competitive under specified conditions.

At a moderate assumption level of fossil fuels prices, 4.4 GW of the renewable energy capacity potentially available could now become cost-effective for replacing conventional fuel-generating capacities to produce electricity in Vietnam. Of the capacities that could operate cost-effective, small hydro energy accounts for 45.5%, geothermal accounts for 31.8%, and biomass energy (bagasse, rice husk, and paddy straw) accounts for the remaining 22.7%. With the contribution of renewables capacities, the share of electricity generation provided by coal fuel could be reduced by 5%. This would reduce the total cumulative CO_2, SO_2, and NO_X emissions by 8.2%, 3%, and 4%, respectively during the period 2010-2030.

In terms of energy resource conservation and energy security, using renewables could potentially reduce the use of domestic coal and natural gas for producing electricity by 141.4 million tons and 1.53 billion m^3, respectively for the period 2010-2030. The country would need to import only 303.8 million tons of coal and 75.5 billion m^3 of natural gas and 377 TWh during 2010-2030, instead of 311.2 million tons of coal, 78.4 billion m^3 of natural gas, and 386 TWh that must be imported over the same period in the scenario of none using renewables.

Renewables are called in the following order. Hydro energy (small and mini) accounts for the largest portion to produce electricity in baseline analysis scenarios as well as in sensitivity analysis scenarios. The electricity production of small and mini hydro energy would be increasingly exploited up to its maximum potential of 4 GW to meet the requirement of energy independence and energy security over the specified period.

At higher level of fuels prices, mini hydro with limited capacity of 100 MW and additional small hydro capacity of 330 MW would be added to cost-effective generation sources.

Wind power and wood biomass enter the grid-connected generation portfolio last, unless large (but plausible) changes in policy, market or technological conditions occur. More specifically, building upon Khanh, Q. Nguyen (2007b), the study suggests that wind power could be cost-competitive at high fossil fuel prices (i.e. levels reached in 2008), if its cost falls to approximately 900 US$/kW or if the fossil fuel supply from both import and domestic sources are strongly constrained (see SA9 through SA11 cases). If the regulator wishes to maintain its option to use wind power, it should already take into account its specificities when planning the grid and the capacity expansions. Likewise, power generation based on wood energy could become cost-effective provided that its cost falls around 1500 US$/kW or if the fossil fuel supply from both import and domestic sources are strongly constrained (see SA9 through SA11 cases).

In contrast to the other RETs, solar grid-connected generation technology never becomes cost-competitive with fossil options in the IRP simulations to 2030. Nevertheless, it keeps a role for providing electricity to people off-grid.

This paper focused on the role of renewables for grid-connected power generation. They may play an even larger role in off-grid electrification in remote areas. Vietnam has more than 70% of population living in these areas, where connecting people to the grid would is expensive, complicated or impossible. Over the last several decades, Vietnamese Government has extended enormous efforts to bring electricity to everybody. At the end of 2005, 88% of households or 95% of communes had access to electricity. According to the Government's rural electrification plan for the period 2001-2010, the remaining 400 communes containing 2 million households, which are un-reached by grid-extension will be supplied with electricity energy with off-grid connected renewable energy options such as mini and micro hydro, solar photovoltaic, and wind generator in forms of standalone and household-sized (Electricity of Vietnam, 2006a).

To conclude, IRP results suggest that the country's available renewable energy sources could potentially contribute to satisfy the soaring electricity demand, mitigate polluting emissions, and enhance energy independence and security over 2010-2030. To realize these economic potentials, many barriers remain to be lifted:

Financial and Infrastructural barriers: As the national energy portfolio is increasingly dominated by fossil fuels, under the existing regulations the negative externalities of fossil fuels are not incorporated in electricity prices. EVN, the single-buyer of electricity, has no obligation to buy from renewable energy projects at a price reflecting the full social benefits of clean energy sources. Renewable energy costs, thus, are still above conventional energy prices. Furthermore, there is a lack of commercial business and infrastructure to provide renewable electricity-generation equipment and services, and a limited access to finance for customers, businesses and project developers.

Information, Capacity and Technical barriers: There is insufficient awareness/information on renewable technologies and data on the national potential of renewable energy sources. Furthermore, inadequate investment for research and development (R&D) leads to unreliable national estimates of renewable energy sources and their technological development, and makes it difficult for planning programs. Moreover, lacks of access to technology, skilled manpower, training facilities and R&D facilities are so far hindering the promotion of renewable energy technologies in Vietnam.

Institutional and Legislative barriers: Insufficient co-ordinations and multiplicity bodies within the Government authorizations responsible for the deployment of renewable energy usage have been described as a major barrier to the successful adoption of these technologies. Specially, the current policy and regulatory framework for promoting the usage of renewable energy is inadequate to drive its development.

Unless these barriers are removed, “Renewable Energy, a large potential in Vietnam wasted” is likely to remain a popular theme in Vietnamese media.

Acknowledgements

We thank Professor Ram M. Shrestha of the Energy Program of Institute of Technology in Bangkok, Thailand for his valuable advice on how to develop this work. All errors and opinions remain ours. This work has been implemented at the Centre International de Recherche sur l'Environnement et le Développement (CIRED, France) under a research grant for a Ph.D. program offered by the Centre National de la Recherche Scientifique (CNRS) of France. The material was first presented at 31st IAEE International Conference held on 18-20 June 2008 in Istanbul, Turkey and at the 16th EAERE Annual Conference held on from 25 to 28 June, 2008 in Gothenburg, Sweden.

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Figures and Tables

Table 1: Assessment of the potential for renewable energies to supply electricity in Vietnam

Energy resources	**Economical potential**	**Current development in 2005**	**Future development planned up to 2025 by Vietnamese agencies**	**Reference sources**
Hydro	84 TWh/yr ([1])			
+ Large hydro (>30 MW)	18-20 GW	Approximately 4200 MW, equivalent to 18 TWh/yr, exploited from hydro	16.6 GW by 2020	Electricity of Vietnam, 2006a, 2006c; Institute of Energy, 2006b, 2006c; Nguyen Khac, 2007
+ Small hydro (<30 MW)	2-4 GW		2.5-3.2 GW	
+ Mini hydro (<1 MW)	100 MW			Electricity of Vietnam 2006a, 2006c; Institute of Energy, 2006b
Hydro pump storage	10.2 GW	Negligible	10.2 GW	
Geothermal	1.4 GW ([2])	Negligible	300-400 MW by 2020	Hoang, H. Quy, 1998; Hoang and Ho, 2000; Institute of Energy 2006b, 2006c
Wind energy	120.5 GW ([4])	Negligible	500 MW	TrueWind, 2001; Khanh 2007a; Institute of Energy, 2006b, 2006c
Solar energy	1 GW ([3])	Negligible	2-3 MW	Institute of Energy, 2006b, 2006c
Rice husk	250 MW	Negligible		Nguyen L.T, and Q.C. Tran 2004; Enerteam 2001; BCSE, 2005; Institute of Energy, 2006a, 2006b, 2006c
Paddy straw	550 MW	Negligible	500 MW	
Bagasse	200 MW	Negligible		
Wood residue	100 MW	Negligible		

([1]) The economic potential consists of total large, medium, small, and mini hydro energy; ([2]) This economical potential is assumed to be used entirely for electricity generation, with none used for heating purposes; ([3]) This economical potential is assumed as the input potential in the IRP model
([4]) This economical potential of wind energy in Vietnam is estimated with different feed-in tariffs varying from 5 to 8 $cent/kWh. Due to the intermittent nature of wind energy, it is a common technical practice that only 20% of total generation system capacity installed could be realistically integrated by wind capacity before 2020 (Hannele Holttinen et al, 2006). Thus, 20 GW of wind capacity, equivalent to 20% of total generation system installed capacity in Vietnam in 2030 is assumed as maximum wind energy feasibly developed for producing electricity over 2010-2030 in the IRP model.

Table 2: Characteristics of selected candidate generation technologies

Candidate plants	Capital cost ($/kW)	Efficiency (%)	Fixed O&M cost ($/kW month)	Variable O&M cost ($/MWh)	Emission factor (kg CO_2/MWh)
Conventional coal	1100	40	2.8	0.15	880
Supercritical coal	1200	43	2.8	0.15	800
IGCC coal	1300	45	3.55	0.15	704
NGCC gas	700	54.63	1.98	0.99	370
Steam Oil	900	43.57	1.63	1.48	730
Solar grid connected	5500	100	2.5	0	0
Wind turbine	1000-1300	100	1.35	0	0
Geothermal	1700-2000	100	2.38	0	0
Very large hydro	1120	100	0.54	0	0
Medium and large hydro	1100 - 1500	100	0.76	0	0
Small and mini hydro	1200 - 1600	100	1.5	0	0
Bagasse direct combustion	850	23	3.58	5	71.64
Biomass IGCC	1600	38.30	3.75	2.9	71.64
Wood IGCC	1600	38.30	3.75	2.9	71.64

Source: Institute of Energy (2006a, 2006 b, 2006c), Electricity of Vietnam (2006a, 2006b)

Table 3: Fuel prices (based on 2005) assumed in scenarios and in sensitivity analysis

Fuel type	Scenario analysis		Sensitivity analysis	
	Fuel prices ($/Gcal)	Escalation rate (%)	Fuel prices ($/Gcal)	Escalation rate (%)
Domestic coal (Anthracite)	5	1.5	7.142	1.5
Imported coal (Bitumen)	6.15	1	9.23	1
Imported FO	28.37	2	50.66	2
Imported DO	30.79	2	56.7	2
Domestic natural gas	15.87	2	17.46	2
Imported natural gas	18.25	1.5	23.8	1.5
Bagasse	0.781	1	0.781	1
Rice husk	0.71	1	0.71	1
Paddy Straw	0.625	1	0.625	1
Wood residue	4.4	1	4.4	1

Source: Institute of Energy (2005, 2006a, 2006b, 2006c), Electricity of Vietnam (2006a, 2006b), World Energy Outlook, IEA 2006.

Table 4: Estimated electricity load demand in different scenarios for the period of 2010-2030. The same transmission and distribution loss (%) and used electricity (%) are applied in all three scenarios.

Items	Scenario	2010	2015	2020	2025	2030
Peak load demand (MW)	Average	18947	31037	46696	68416	83165
Peak load demand (MW)	High	19730	32430	48570	70790	86620
Peak load demand (MW)	Low	17940	27639	39286	55376	68473
Transmission and distribution loss (%)	Common	10.8	9.6	8.5	7.5	7.5
Used electricity (%)	Common	3.0	3.6	4.0	4.2	4.3

Source: Institute of Energy (2006a, 2006b, 2006c, 2006d), Electricity of Vietnam (2006a)

Table 5: Quantitative estimates and assumptions of fuels (domestic and imported) and electricity import to meet electricity demand in Vietnam during 2010-2030.

Estimated quantity of imports by Vietnam (unit/year)					Assumptions in the IRP model (unit/year)	Assumptions for sensitivity analysis in IRP (unit/year)
Energy fuel/electricity imported	Demand for import in 2020	Demand for import in 2030	Minimum quantity available	Feasible quantity available	Maximum imports in 2020 and 2030	Maximum imports in 2020 and 2030
Coal (million tons)	29	32	29	32	29	29
Gas (billion m^3)	7	13	4-5	9	9	No import
Electricity (TWh) from hydro sources	17-35	35-64	17-34	37	24 and 37	17

Estimated domestic fuels using to produce electricity 2010-2030

Period	2010-2020	2020-2030
Domestic gas used in all cases	≤14 billion m^3 per year	≤20 billion m^3 per year
Domestic coal used in B1, B2 cases	no limitation	No limitation
Sensitivity analysis cases		
+ Coal limitation scenario No.1	≤47 million tons per year	≤100 million tons per year
+ Coal limitation scenario No.2	≤47 million tons per year	≤82 million tons per year
+ Coal limitation scenario No.3	≤47 million tons per year	≤73 million tons per year

Source: Institute of Energy (2006a, 2006b, 2006c), Electricity of Vietnam (2006a, c)

Table 6: Electricity capacity generation in Vietnam, 2010-2030. B1: with no RETs. B2: with RETs. Simulations of the Vietnamese power sector were carried out using the IRP model.

	Renewable sources			Fossil fuel sources						
	RETs	**Large Hydro**	**Hydro Pump Storage**	**Domestic Coal**	**Coal import**	**Domestic Gas**	**Gas import**	**Oil**	**Electricity import**	**Total**
				Generation capacity installed (MW)						
B1	0	14124	10200	35394	12000	13200	7500	600	6815	99833
B2	4432	14124	10200	31194	12000	13200	7500	600	6815	100065
				Electricity generation (GWh)						
B1	0	1190299	172234	2235498	987940	1887615	509032	21405	385559	7389582
B2	369826	1190300	172217	1906878	964418	1878085	490006	21405	376974	7370108

Table 7: Technical, economic, and environmental comparison between the B1 scenario (no RETs) and the B2 scenario (with RETs) for the period 2010-2030. Simulations of the Vietnamese power sector were carried out using the IRP model.

Point of comparison	Without renewables	With renewables	Avoided (absolute)	Avoided (%)
1. Electricity utility implications				
Total generation capacity added over 2010-2030 (MW)	81788	82020	-232	-0.28
Total generation capacity installed up to 2030 (MW)	99833	100065	-232	-0.23
Total electricity generation over 2010-2030 (TWh)	7389.6	7370.1	19.5	0.26
Average loss of load probability (%)	0.05	0.01	0.04	83.15
Average expected energy not served (GWh)	57.69	8.51	49.18	85.25
Average thermal efficiency (%)	46.72	47.20	-0.48	-1.03
Average capacity factor (%)	64.69	64.31	0.38	0.59
2. Implications for energy resource conservation and energy security				
Domestic fuel consumption over 2010-2030				
- Coal (million tons)	971	830	141.4	14.56
- Gas (billion m^3)	296	295	1.53	0.52
Imported fuel consumption over 2010-2030				
- Coal (million tons)	311	304	7.41	2.38
- Gas (billion m^3)	78	75	2.93	3.74
- Oil (million tons)	5.02	5.02	0.00	0.00
Imported electricity during 2010-2030 (TWh)	385.6	377	8.6	2.23
3. Economic Implications				
Fuel and variable O&M cost during 2010-2030 (million $)	26 864	25 748	1,116	4.15
Total discounted planning cost during 2010-2030 (million $)	48 167	46 905	1,262	2.62
Average incremental cost AIC ($cent/kWh)	4.01	3.98	0.03	0.75
Long run average cost LRAC ($cent/kWh)	2.97	2.90	0.07	2.36
4. Environmental Implications				
Total emissions during 2010-2030				
- CO_2 emission (Mton)	3 825	3 512	313	8.20
- SO_2 emission (Kton)	2 601	2 520	81	3.13
- NO_X emission (Kton)	6 015	5 767	248	4.12

Table 8: Power capacity and electricity generation by type of renewables and fossil fuels generation sources in Vietnam, 2010-2030. B2: baseline scenario using RETs. SA1-SA7: different sensitivity analysis scenarios. Simulations were carried out using the IRP model.

Scenarios	Mini hydro	Small Hydro	Biomass	Wood	Wind	Geo-thermal	Solar	Large Hydro	Dom-Coal	Imp-Coal	Dom-Gas	Imp-Gas
Total generation capacity in 2030 (MW)												
B2:	0	2 032	1 000	0	0	1 400	0	14 124	31 194	12 000	13 200	7 500
SA1: No fuel gas import	0	2 032	1 000	0	0	1 400	0	14 124	39 294	12 000	13 200	-
SA2: Limited electricity import (maximum amount of 17 TWh/year)	0	2 032	1 000	0	0	1 400	0	14 124	38 394	12 000	13 200	3750
SA3: Low load demand	0	2 032	1 000	0	0	1 400	0	14 124	14 994	12 000	13 200	7 500
SA4: High load demand	0	2 032	1 000	0	0	1 400	0	14 124	35 094	12 000	13 200	7 500
SA5: High fuel prices	100	2 432	1 000	0	0	1 400	0	14 803	36 294	12 000	13 200	7 500
SA6: High fuel prices + wind technology cost falls to 900US$/kW	100	2 332	1 000	0	4 622	1 400	0	14803	36 594	12 000	13 200	7 500
SA7: High fuel prices + wood energy technology cost falls to 1500US$/kW	100	2 332	1 000	100	0	1 400	0	14803	36 594	12 000	13 200	7 500
SA8:=SA1+SA2+SA5+no limited domestic coal supply	100	3 917	1 000	0	0	1 400	0	17 253	38 094	12 000	13 950	-
SA9:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.1	100	3 917	1 000	100	7 888	1 400	0	18 089	34 894	12 000	13 950	-
SA10:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.2	100	3 917	1 000	100	22 276	1 400	0	17 561	28 394	12 000	13 950	-
SA11:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.3	100	3 917	1 000	100	29 478	1 400	0	17 561	25 394	12 000	13 950	-

Scenarios	Mini hydro	Small Hydro	Biomass	Wood	Wind	Geo-thermal	Solar	Large Hydro	Dom-Coal	Imp-Coal	Dom-Gas	Imp-Gas
Total electricity generation during 2010-2030 (GWh)												
B2:	0	146 497	99 061	0	0	124 268	0	1 190 300	1 906 878	964 418	1 878 085	490 006
SA1: No gas imported	0	154 954	99 061	0	0	124 268	0	1 190 304	2 505 917	985 802	1 757 930	-
SA2: Limited electricity imported (maximum amount of 17 TWh/year)	0	152 135	99 061	0	0	124 268	0	1 190 302	2 405 553	983 664	1 836 735	200 901
SA3: Low load demand	0	132 678	96 129	0	0	124 268	0	1 177 379	1 023 480	857 499	1 858 525	344 188
SA4: High load demand	0	148 511	99 061	0	0	124 268	0	1 190 303	2 146 287	983 663	1 875 945	488 037
SA5: High fuel prices	4 917	167 911	99 061	0	0	124 268	0	1 224 489	2 187 057	964 419	1 911 078	96 900
SA6: High fuel prices + wind technology cost falls around 900US$/kW	4 917	162 994	99 061	0	240 244	124 268	0	1 224 489	2 283 237	878 882	1 913 122	89 596
SA7: High fuel prices + wood energy technology cost falls around 1500US$/kW	4 728	162 994	99 061	10 612	0	124 268	0	1 224 490	2 283 585	878 882	1 907 449	87 671
SA8:=SA1+SA2+SA5+no limited domestic coal	4 917	200 482	99 061	0	0	124 268	0	1 303 867	2 550 523	819 007	1 875 183	-
SA9:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.1	4 917	200 482	99 061	2 948	21 883	124 268	0	1 315 901	2 535 185	816 868	1 856 990	-
SA10:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.2	4 917	200 482	99 061	5 159	101 434	124 268	0	1 304 684	2 418 797	819 007	1 881 313	-
SA11:=SA1+SA2+SA5+ limited domestic coal supply as scenario No.3	4 917	200 482	99 061	5 896	161 836	124 268	0	1 309 143	2 347 359	819 007	1 884 104	-

Figure 1. Distribution of electricity generation sources in Vietnam for the period 2005-2010

Source: Institute of Energy, 2006b

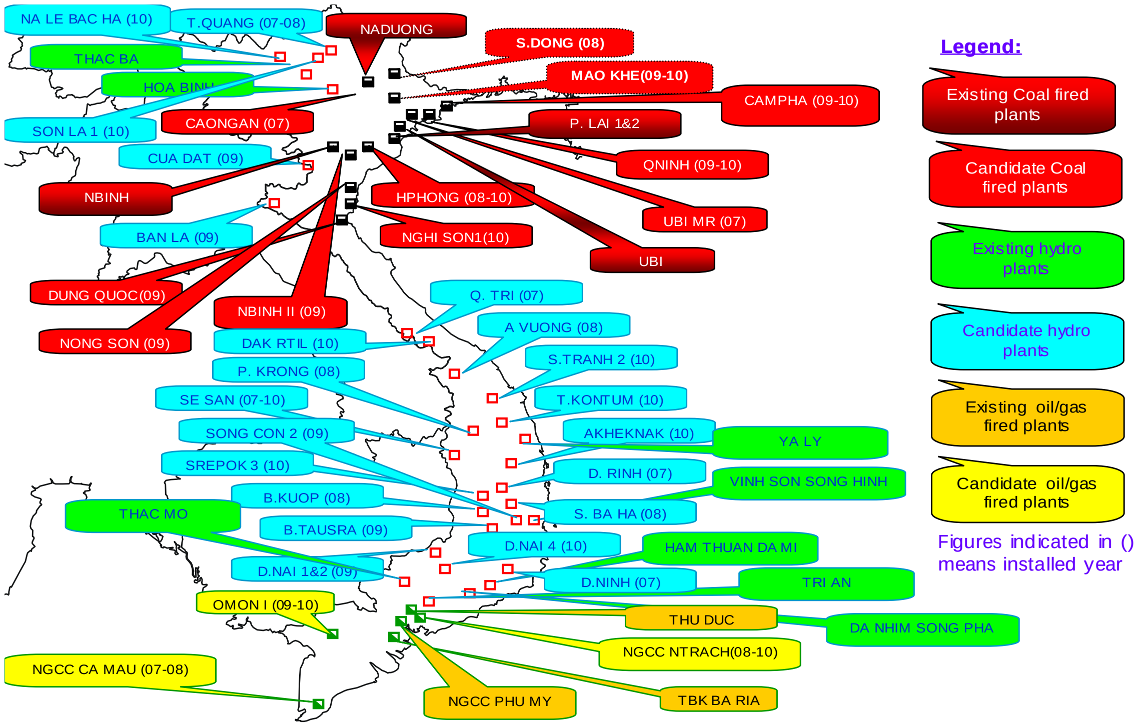

Figure 2. History and forecasts of electricity energy and peak load demand in Vietnam, 1995-2030.

Source: Institute of Energy (2006b, c, d)

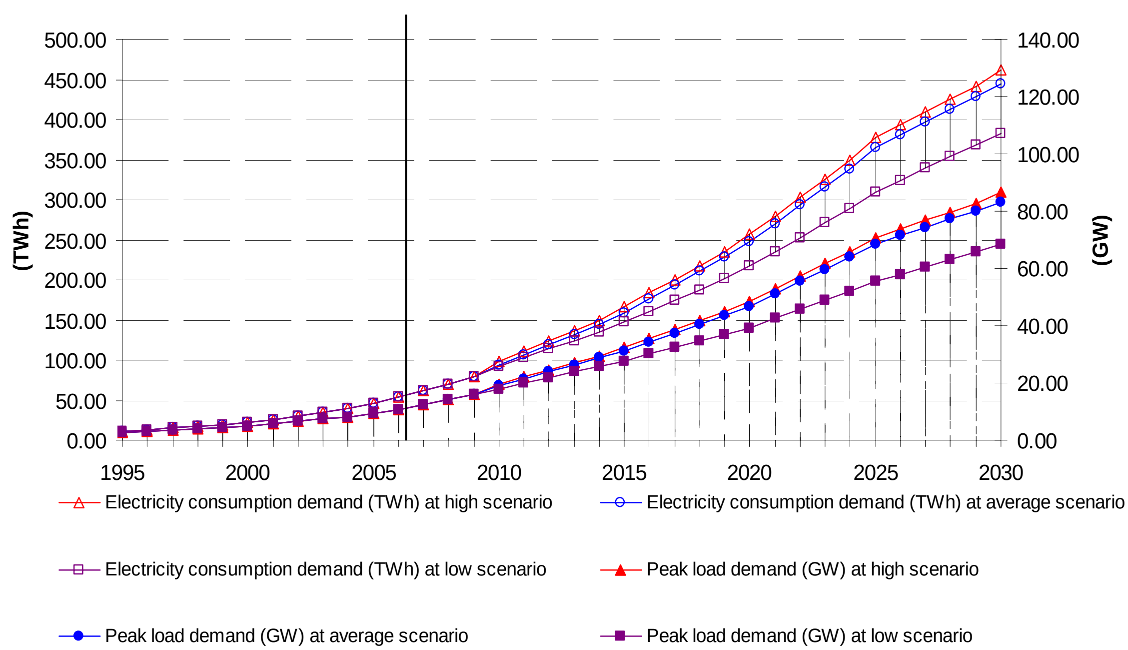

Figure 3. Annual fuel demand of domestic natural gas (billion m^3) and coal (million tons) for electricity generation during 2010-2030 in the B1 and B2 scenarios

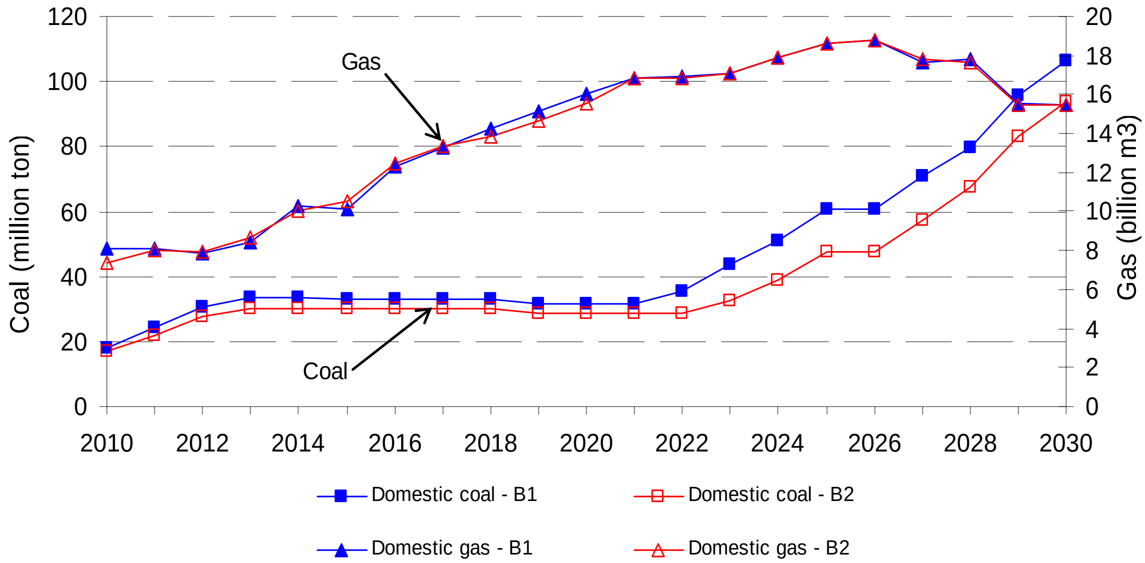

Figure 4. The annual demand for imported natural gas (billion m^3), coal (million tons), and electricity (GWh) for electric power generation during 2010-2030 in the B1 and B2 scenarios

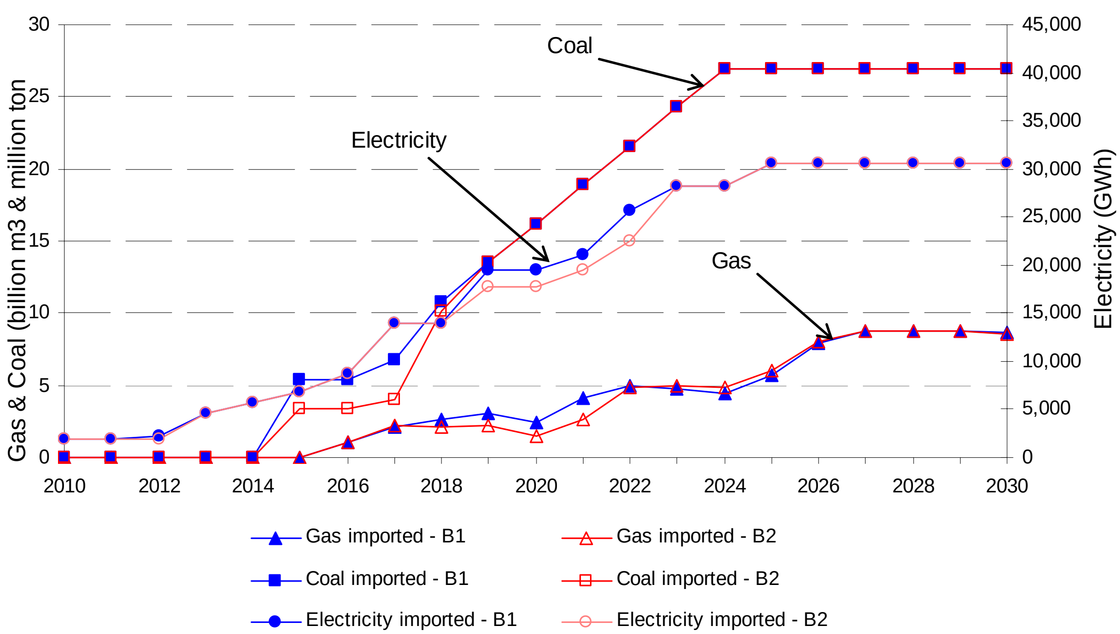

Figure 5. Annual component costs of electricity generation (GWh) during 2010-2030 in the B1 and B2 scenarios