Analysis of the Optimal Configuration of Energy Transportation Infrastructure in Asia with a Linear Programming Energy System Model

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Abstract

It has become important to answer the questions of what energy related infrastructure, such as transcontinental natural gas pipelines and international electricity grids, should be constructed in Asia/Eurasia, and how energy demand should be satisfied there securely, economically, and environmentally benignly over the next several decades. The purpose of this study is to investigate the possible future configuration of energy and CO_2 related infrastructure in the region of Asia/Eurasia that neighbors Japan.

We have been developing a large-scale energy related infrastructure model, which uses linear programming techniques to minimize inter-temporally the sum of the discounted total energy system up until the year 2050. The model explicitly involves intra-regional transportation networks of fuels, electricity, and recovered CO_2 among about 90 nodes in Asia/Eurasia. The model illustrates concrete geographical distributions of demand and supply of various primary energy, CO_2 recovery and disposal, and transportation flows of the fuels, electricity, and recovered CO_2 among the nodes. The nodes are connected with plausible land and/or ocean transportation routes. Coal freight trains, oil pipelines, natural gas pipelines, power transmission lines, and CO_2 pipelines are considered as the specific measures for land transportation. We assume ocean transportation routes for coal, oil, and natural gas between each pair of the coastal nodes in the model. Coal bulk carriers, oil tankers, and LNG (Liquefied Natural Gas) tankers are considered as the specific measures for ocean transportation. The specific capacity of each transportation route is determined as the result of minimization of the total energy system cost.

Although a great deal of uncertainty remains, the preliminary results indicate that the development of gas production and transportation infrastructures appears to be a robust energy supply option for Asian countries, and that the economic validity of the development of region-wide electricity grids among Asian countries is not necessarily obvious. The results suggest that transporting coal and natural gas by rail or pipeline (as appropriate) and generating electricity close to the energy-consuming cities is generally more economical than generating electricity at mine mouths or wellheads and transmitting electricity by power

transmission lines.

Keywords: energy transportation infrastructure, Asia, CO_2 recovery and disposal, energy system model, linear programming

1. Introduction

While energy demand in China, Southeast Asia, and East Asia is projected to grow substantially over the coming decades, there has been a large amount of concern about the rapid increase in anthropogenic CO_2 emissions from fossil-fuel burning and the increase in the atmospheric CO_2 concentration, which is expected to influence the problems that cause global warming.

Coal is an abundant and broadly distributed fossil fuel in Asia and Eurasia and is expected to continue to be a major energy resource. Although the price of coal per unit of calorific value has been relatively inexpensive in the region, the growing demand for coal will not be met without the extensive development of transportation infrastructure such as railroads and bulk carriers. In the case of crude oil, it is not so plentiful in the region as is coal, and it is unevenly distributed. Oil supplies for Asia and Eurasia continue to be increasingly dependent upon the Middle East, and such over-dependency of oil procurement on a single geopolitical region may potentially aggravate the energy securities of these countries. Natural gas is a clean and high quality fuel. Its combustion generates less CO_2 than any other fossil fuel on a per calorie basis. From the viewpoint of environmental protection, natural gas is the best substitute for oil and coal. However, enormous capital investment in transportation infrastructure (e.g. liquefied natural gas tankers, liquefaction and re-gasification plants, as well as extensive pipelines in Asia and Eurasia) will be required in order to increase the share that natural gas provides of total primary energy supply for this region.

In such a circumstance, the development and exploitation of energy resources in Asia and Eurasia--i.e., East Siberia and the Russian Far East--have attracted considerable attention. It has become increasingly important to answer the question of how primary energy requirements for this region should securely and economically be provided, as well as the question of what energy infrastructure, such as transcontinental natural gas pipelines and long distance power transmission lines, should be constructed, with particular attention to CO_2 emission abatement from fossil fuel use.

In response to the above questions, the purpose of this study is to obtain insights into the optimal future configuration and operation of energy infrastructure in Asia and Eurasia, and also the potential roles of CO_2 recovery and sequestration technologies. For this purpose, the authors have developed large-scale energy system models, which use linear-programming techniques to minimize inter-temporally the sum of the discounted total energy system up until the year of 2050[1][2]. The model explicitly involves intra-regional transportation networks of fuels and recovered CO_2 among 84 representative nodes of the network for Asia and Eurasia, as well as energy conversion facilities including those for hydrogen production and methanol synthesis. The model tries to illustrate concretely geographical distributions of demand and supply of various fuels by node, CO_2 recovery and sequestration by node, and transportation flows of the fuels and recovered CO_2 among the nodes.

In the following sections, the outline of the current version of the energy model and a summary of its computational results are presented.

2. Energy infrastructure model for Asia and Eurasia

2.1 Geographical coverage of the energy model

The geographical coverage of the model is the whole world. As seen in Figure 1, the Asian region is modeled with 84 representative nodes of large cities and production sites, and the rest of the world is disaggregated into five regions. The model has 58 spatially distributed nodes, which represent energy-consuming areas in Afghanistan, Australia, Bangladesh, Bhutan, Brunei, Cambodia, China, India, Indonesia, Iran, Iraq, Japan, Kazakhstan, Kyrgyz, Laos, Malaysia, Mongolia, Myanmar, Nepal, North Korea, Pakistan, Philippines, Singapore, South Korea, Tadzhikistan, Thailand, Turkmenistan, Uzbekistan, and Vietnam. The model also assumes 26 energy production nodes, which include those in East Siberia and the Russian Far East.

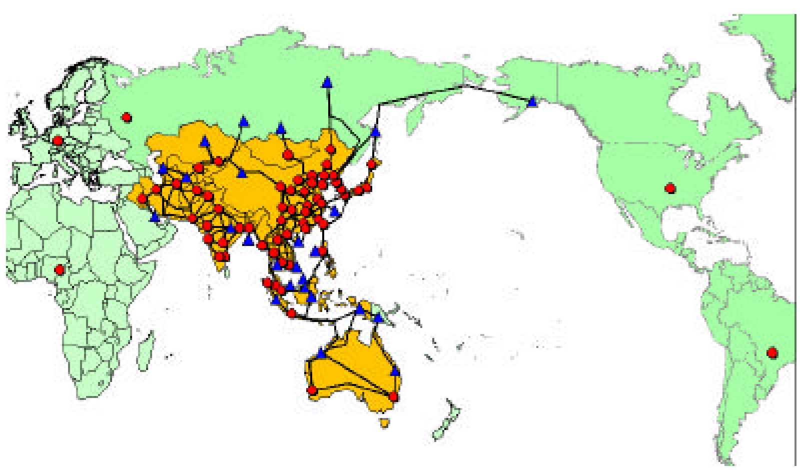


Figure 1 Representative nodes and land transportation routes considered in the model

As seen in Figure 1, the model assumes an energy transportation infrastructure network of 84 nodes. The nodes are connected with plausible land and/or ocean transportation routes. Coal freight trains, oil pipelines, natural gas pipelines, long distance power transmission lines, and CO_2 pipelines are considered as the specific measures for land transportation. We assume ocean transportation routes for coal, oil, and natural gas between each pair of the coastal nodes in the model, but these ocean routes are not indicated in Figure 1. Coal bulk carriers, oil tankers, and LNG (liquefied natural gas) tankers are considered as the specific measures for ocean transportation. In the current version of the model, ocean transportation of CO_2 and inter-node transportation of hydrogen and methanol are also taken into account. The specific capacity of each transportation route is determined as the result of minimization of the total energy system cost.

2.2 Outline of the system structure of the energy model

Figure 2 indicates the assumed possible energy flow at each node in this energy model. Fossil fuel gasification, methane and methanol synthesis, hydrogen production, and electric power generation are considered as technological options for energy conversion. Each node has the possibility to have any one of the facilities of the above-mentioned energy conversion processes. An elaborate integration of these conversion plants with CO_2 recovery facilities provides for a large source of low carbon-intensive fuels with little additional CO_2 emissions from their conversion processes. Such an integrated energy system can be expected to contribute to remarkable reductions in CO_2 emissions from end-use sectors.

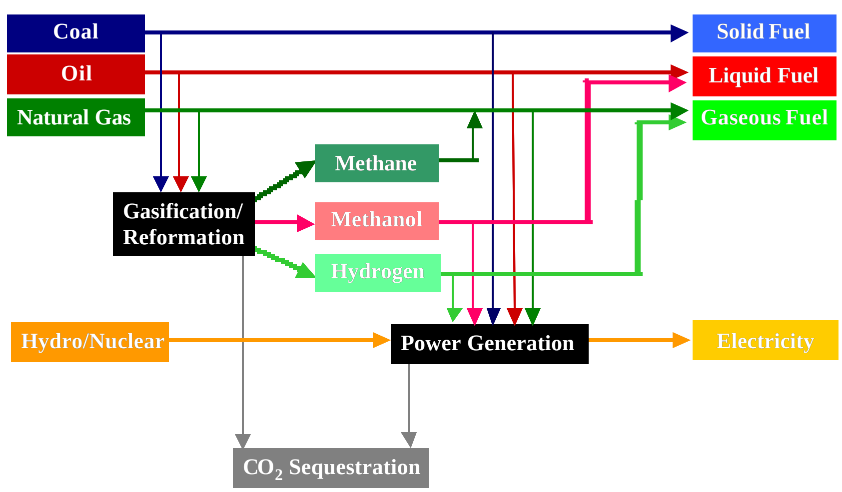


Figure 2 Assumed energy flow by node

With respect to the electricity generation sector, the model explicitly takes into account daily load duration curves expressed simply with three time periods (peak, intermediate, and off-peak), as seen in Figure 3, so as to determine how each type of power plant will be operated in accordance with diurnal variation of electricity demands. This is because the capacity factors of electric power plants are supposed to have a large influence on their economic characteristics. The future contributions of nuclear and hydraulic power plants in the model are exogenously determined prior to the cost minimization in this study.

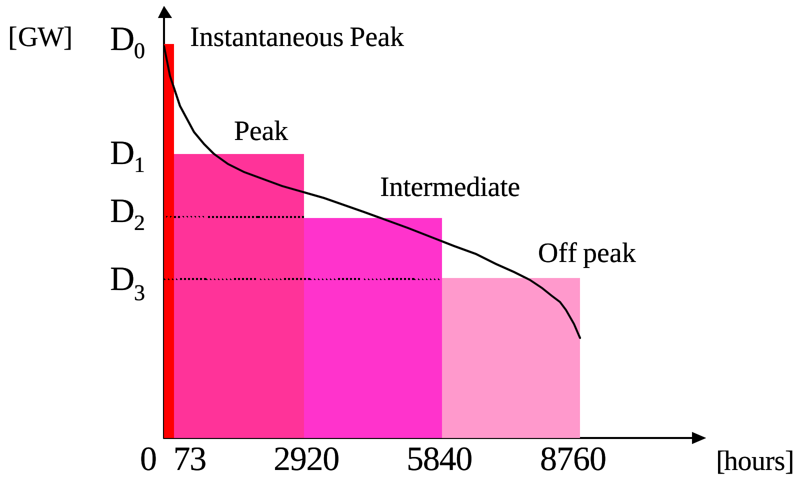


Figure 3 Assumed load duration curve

One of the notable features of the model is that it can explicitly analyze the roles of various processes for CO_2 recovery and sequestration in the energy system. Figure 4 illustrates possible CO_2 recovery and sequestration processes. As specific measures for CO_2 recovery, the model takes into account both chemical absorption from flue gas of thermal power plants and physical absorption from the output gases of fossil fuel reforming processes. There are two major methods for CO_2 sequestration: ocean sequestration and subterranean sequestration. Subterranean sequestration is classified into three types: 1) injection of CO_2 into oil wells for enhanced oil recovery (EOR) operation; 2) storage of CO_2 in depleted natural gas wells; and 3) sequestration of CO_2 in aquifers. The model built here takes account of all these sequestration methods other than aquifer sequestration, and can assess their future potentials by node in the model.

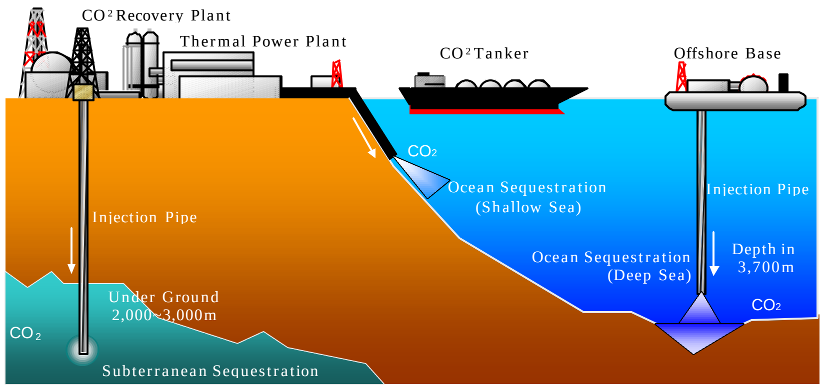


Figure 4 CO_2 recovery and sequestration

In the case of ocean sequestration, unquestionably the storage capacity of the ocean is sufficiently large, but it is very difficult to estimate specific costs for the secure deposition of CO_2 in the ocean. This is due to the fact that many types of uncertainties exist: changes in the pH of the seawater, clathrate formation on the seabed, and the resultant ecological impacts. Notwithstanding these serious uncertainties about ocean sequestration, we introduced it into the model to get an insight into the economic feasibility of ocean sequestration as one of the technological options.

The recovered CO_2 is assumed not only to be disposed of, but also to be recycled as a chemical feedstock for methanol synthesis. This option can build up a kind of carbon cycle within the energy system, but the amount of CO_2 thus recycled is limited by the regional capability of hydrogen provision.

2.3 Mathematical formulation of the model

The model built here is mathematically formulated as a multi-period inter-temporal linear optimization problem with linear inequality and equality constraints. The constraints represent supply and demand balances of each type of energy by node, energy and CO_2 balances in energy conversion processes, and state equations for several inter-temporal dynamics, such as the depletion of fossil fuel resources and subterranean CO_2 reservoirs' capacities, the vintage structures of various facilities in the energy system, and so forth. The objective function of the problem is defined as the sum of the discounted total energy system costs distributed over time, which include fuel production costs, levelized plant fixed costs comprising capital and maintenance costs, energy transportation costs, CO_2 recovery and sequestration costs, and carbon taxes. The supply cost curves of fossil fuels by node are expressed as step-wise linear functions with respect to their amounts of cumulative production.

The model seeks the optimal regional development paths of the energy-related infrastructure for the years from 2000 through 2050, at intervals of 10 years, using a linear-programming technique. The model, therefore, does not take into account any nonlinear effects, such as economies-of-scale with respect to unit construction costs of various facilities, especially those of pipelines. Furthermore, for simplicity, all the variables in the model are treated as continuous real numbers, although some of them, such as those expressing the number of tankers, should indeed be treated as discrete integer numbers in the real world.

2.4 Assumed data

2.4.1 Reference energy demand scenarios

The final consumption sector of the energy infrastructure model is disaggregated into the following four types of secondary energy carriers: 1) gaseous fuel, 2) liquid fuel, 3) solid fuel, and 4) electricity. In the case of electricity consumption, as mentioned before, the model explicitly takes into account daily load duration curves expressed simply with three time periods: peak, intermediate, and off-peak.

The future energy consumption in the model is exogenously given as reference scenarios by type, node, and year. The reference scenarios of energy consumption, aggregated by type of secondary energy and by sub-region in this study, are illustrated in Figure 5. These calculations were based upon the method proposed in reference [4], where per capita income is presumed to be the main parameter determining the future trends of per capita final energy consumption by type of secondary energy. According to this method, as per capita income grows higher, grid energies, namely gaseous fuel and electricity, are assumed gradually to increase their shares in total final energy consumption. The energy supplies of relatively low-income countries are assumed to be dependent upon solid fuel. The amounts of energy consumption by node were principally calculated by using the data on geographical distribution of population.

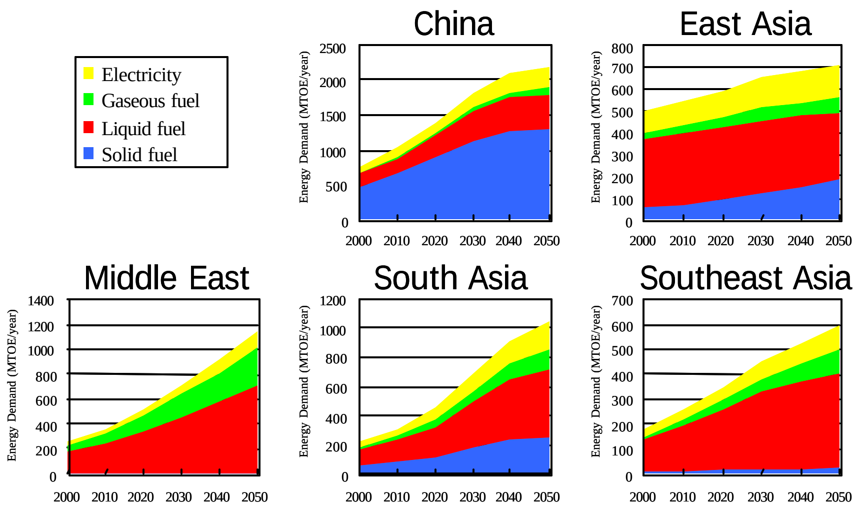


Figure 5 Reference energy demand scenarios by sub-region

2.4.2 Resource amounts and production costs

The resource amounts of coal, crude oil, and natural gas in this study were derived mainly from references [5][6][7][8]. Geographical distributions of fossil fuel resources were partly estimated on the basis of those of the proven reserves. Figure 6 shows our assumption on resource amounts of the fossil fuels by sub-region.

With the wide variety of economic and geological conditions, the production costs of fossil fuels can be estimated only with considerable uncertainty. Since each node must have various economic grades of resources, the production cost curve of each node is expressed in a step-wise linear function with respect to their amounts of cumulative production. Figure 7 describes aggregately the assumed production costs of fossil fuels as functions of their respective resource amounts.

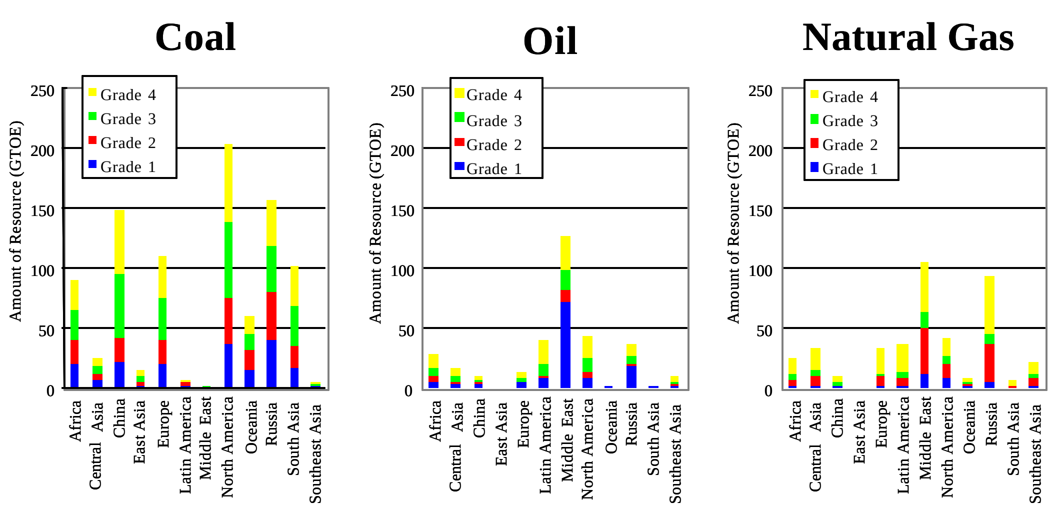


Figure 6 Resource amounts of the fossil fuels by sub-region

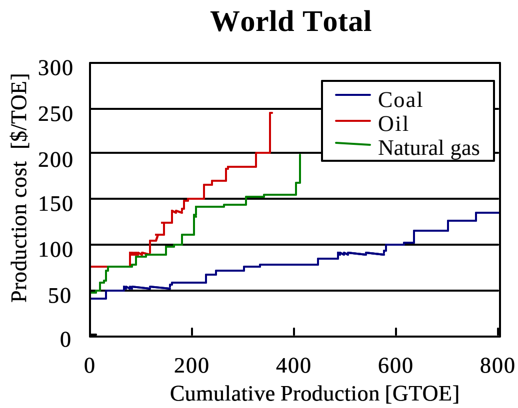


Figure 7 Assumed production costs of coal, oil, and natural gas

2.4.3 Infrastructure construction costs

In this section, we simply show the unit construction costs of each element of the infrastructure. These cost parameters for the model were derived mainly from the estimates made in various references [5][9][10][11][12][13][14][15][16][17].

Table 1 shows assumed characteristics of the energy transportation facilities. Their fixed costs and variable costs are expressed in linear functions with respect to transportation distance L [unit: 1000km]. The costs of ships were deduced from the unit construction cost of ships and their typical operation pattern for loading and unloading. Pipeline costs are assumed to vary between 100% and 200% of the values in Table 1, dependent upon their respective geographical route conditions. For example, an offshore pipeline is assumed to cost twice as much as a land pipeline. For simplicity, the energy losses associated with ocean transportation of coal and oil are neglected here. The lifetime of the pipelines is assumed to be 60 years, and that of the ships and the liquefaction and re-gasification plants 30 years.

Table 1 Assumed characteristics of energy transportation facilities
(L: transportation distance [unit: 1000km])

	Unit	*Unit cost*	*Transportation loss*
Coal freight train	US$/(toe/year)	45.4L	2.2 L (%)
Oil pipeline	US$/(toe/year)	6.2 L	2.3 L (%)
Natural gas pipeline	US$/(toe/year)	22 L	2.3 L (%)
Methanol pipeline	US$/(toe/year)	12.6 L	2.3 L (%)
Hydrogen pipeline	US$/(toe/year)	35.2 L	3.5 L (%)
Coal bulk carrier	US$/(toe/year)	0.94 L +0.78	-
Oil tanker	US$/(toe/year)	0.61 L +0.5	-
Liquefied natural gas tanker	US$/(toe/year)	6.07 L +97.6	0.2 L (%)
Methanol tanker	US$/(toe/year)	1.23 L +1.02	-
Liquefied hydrogen tanker	US$/(toe/year)	13.6 L +213.8	0.2 L(%)
DC power transmission line	US$/kW	89.7 L +23.8	10 L (%)

Table 2 shows assumed characteristics of thermal power plants. Slight improvements in thermal conversion efficiency of the power plants are assumed over the simulation period by node with the variation ranges listed in Table 2.

Table 2 Assumed characteristics of fossil fuel fired power plants

	Construction cost US$/kW	*Efficiency, in percent*
Coal fired	1,300	27~39
Oil fired	750	29~43
Natural gas fired	850	34~49
Methanol fired	1,650	33~49
Hydrogen fueled	1,850	32~47
IGCC	2,000	31~46

In order to reduce the size of the infrastructure model, the future contributions of nuclear and hydroelectric power plants are exogenously given as scenarios by node and year. In this study, we assume that the contribution of these non-fossil power plants will be rather modest and simply assume that their annual generation levels will be kept constant at their respective present levels over the simulation period. The lifetime of electric power generation plants is assumed to be 30 years.

In addition to thermal electric power plants, various types of energy conversion plants, such as a coal gasification plant and a methanol synthesis plant, were introduced as technological options in the model. Figure 8 shows the energy conversion (fuel reforming and synthesis) flows. We assumed two types of synthesis methods for methanol. The lifetime of those energy conversion plants is assumed to be 30 years.

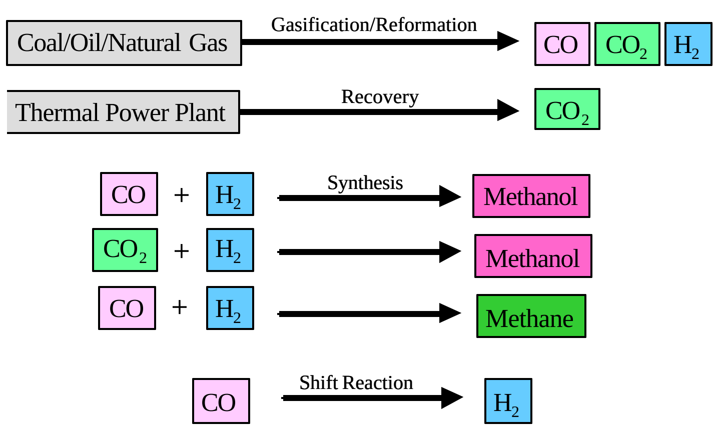


Figure 8 Energy conversion processes assumed in the model

2.4.4 CO_2 recovery, sequestration and recycling

As previously mentioned, one of the notable features of the model is that it can explicitly analyze the roles of processes of CO_2 recovery and sequestration in the energy system. The related costs are shown in Table 3. We assumed that the oil production cost by EOR is 70 US$ per ton of oil equivalent (toe), and that CO_2 can be disposed of at the rate of 0.6 tons of carbon per ton of oil equivalent (t-C/toe) of recovered oil. With respect to depleted gas well injection, the storage capacities are derived from the simple assumption that one CO_2 molecule can replace one CH_4 molecule. For ocean sequestration, recovered CO_2 is assumed to be liquefied, and then to be transported to offshore sequestration sites by tanker. We assumed three grades of ocean sequestration cost, depending upon the transportation distance from a port with a shipment of liquefied CO_2 to the corresponding nearest offshore sequestration site.

Table 3 CO_2 recovery transportation and sequestration costs
(L: transportation distance [unit: 1000km])

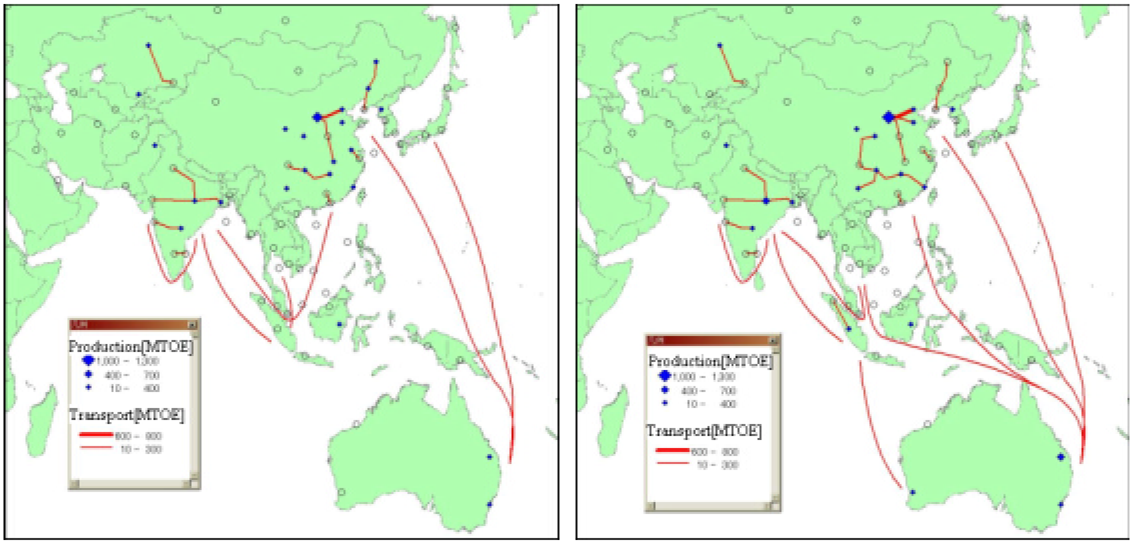
	Unit	*Fixed cost*	*Variable cost*
CO_2 Pipeline	US$/(tC/year)	$54L+11.3$	$1.3L$
CO_2 Recovery	US$/(tC/year)	30	0
CO_2 Liquefaction	US$/(tC/year)	32	0
Depleted gas well injection	US$/tC	0	45
Ocean sequestration	US$/tC	0	100~124

3. Simulation results of the model

This section presents some of the simulation results of the energy infrastructure model. This study assumes three policy cases: a business-as-usual (BAU) case, an investment constraint (INC) case, and a carbon tax (CTX) case. The BAU case does not anticipate either investment constraints or CO_2 abatement policies over the specified time horizon. In the INC case, we assume that the investment in energy transportation infrastructure is limited to under 0.5~1.0% of GDP for specific countries in Asia. In the CTX case, we simply assume the introduction of certain rates of carbon taxes ranging from 100 US$/t-C to 500 US$/t-C, with a central estimate of 300 US$/ t-C.

3.1 BAU case

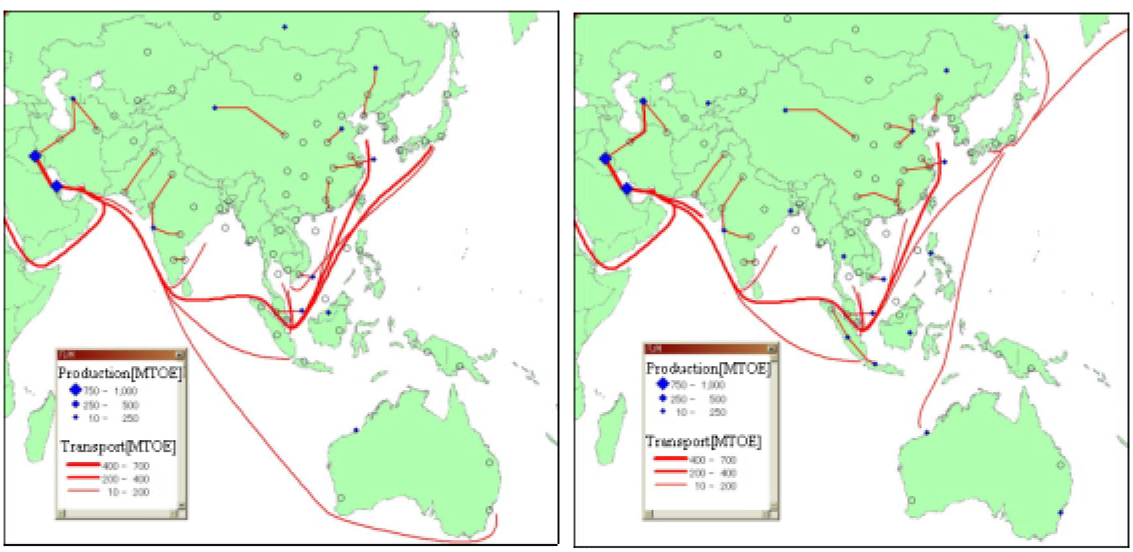
Figure 9 describes the calculated flows of coal in 2030 and 2050. Extensive railroad transportation of coal can be seen among the nodes of Chinese cities. Due to the relatively high transportation costs of coal freight trains, the coal requirements for most of the regions, such as the industrialized coastal regions of China, North Korea, South Korea, and Japan, are to be provided by Australia by means of coal bulk carriers. Because we assume a relatively low production cost for coal in India, the coal demands of Southeast Asia are to be satisfied partly by coal from India.



(in the year of 2030) (in the year of 2050)

Figure 9 Coal production and transportation in the BAU case

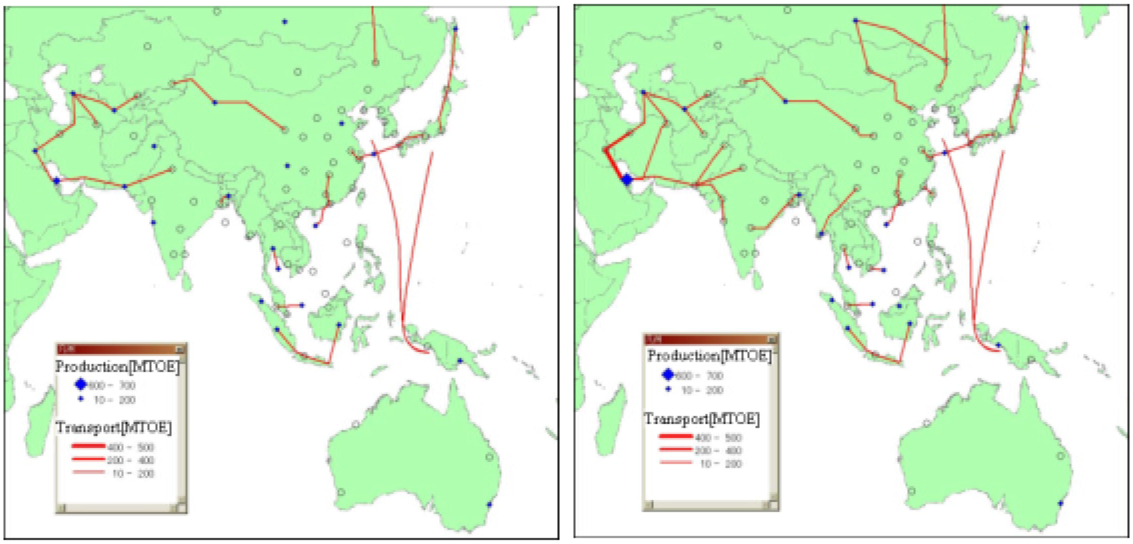
Figure 10 describes the calculated flows of oil in 2030 and 2050. Most of the oil requirements in 2020 and 2050 are to be provided almost exclusively by the Middle East. In the figure, it is interesting to note that certain amounts of oil production can be found around the nodes of the Tarim Basin (Urumchi) and the Caspian Sea.



(in the year of 2030) (in the year of 2050)

Figure 10 Oil production and transportation in the BAU case

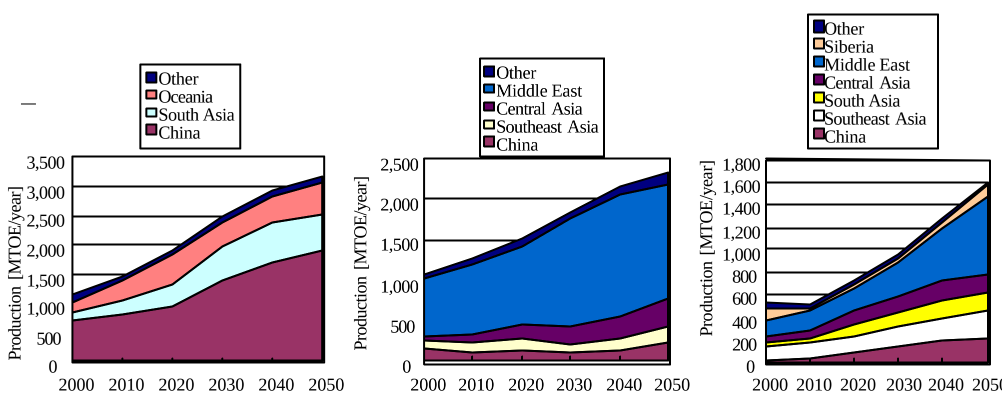
Figure 11 illustrates the calculated flows of natural gas in 2030 and 2050. As seen in the figure, supply sources of natural gas ar e to be geo-politically diversified over the region. For instance, China is provided with natural gas not only by Southeast Asia but also by the regions of the Former Soviet Union. In the case of Japan, LNG tankers are predicted to be the main transportation means and, at the same time, we can see the long distance gas pipeline between the Russian Far East of Sakhalin and the northern part of Japan.



(in the year of 2030) (in the year of 2050)

Figure 11 Natural gas production and transportation in the BAU case

Figure 12 shows the time profiles of regional total fossil fuel production by type, and Figure 13 indicates the time profiles of regional total electricity generation by type. It should be noted that the contributions of hydropower stations and nuclear power stations are exogenously determined under the scenario represented in this figure. From these figures, coal is expected to be the dominant primary energy source in the BAU case, especially for electric power generation in Asia and Eurasia. Even in the BAU case, natural gas is estimated to become the second most important fuel for power generation.



(Coal) (Oil) (Natural gas)

Figure 12 Time profiles of regional total fossil fuel production by type in BAU case

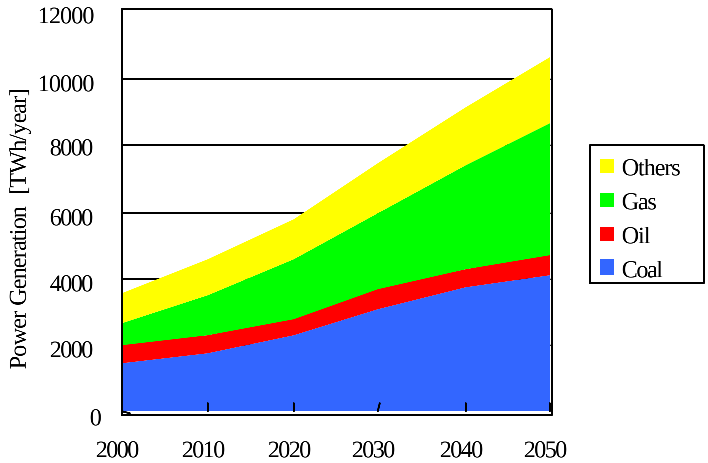
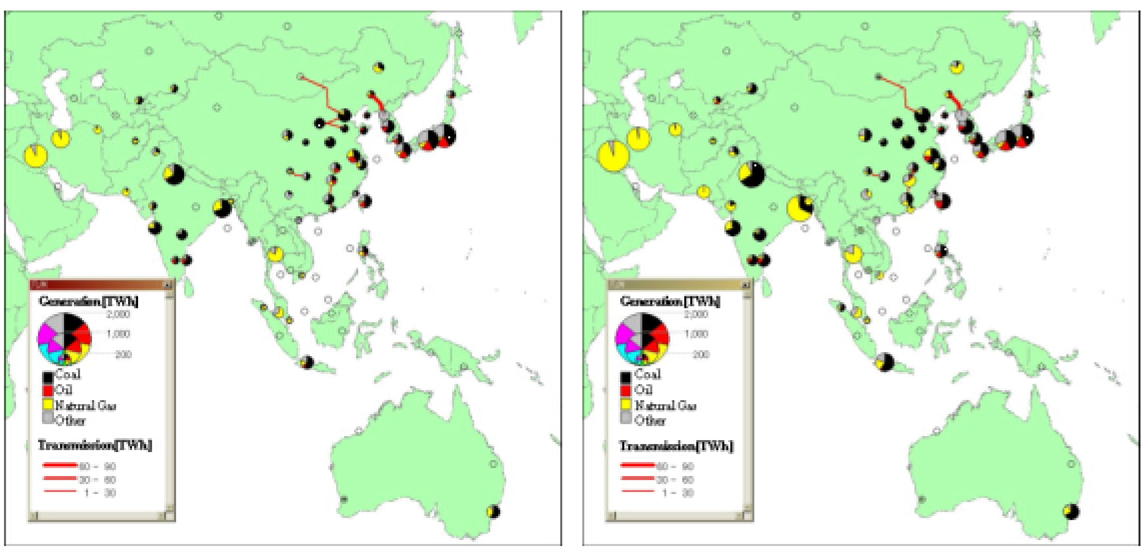


Figure 13 Electricity generation by fossil fuels in BAU case

Figure 14 indicates the computational results for electric power generation mixes by node. This figure suggests that transporting coal and natural gas by rail or pipeline and generating electricity close to the energy-consuming cities is generally more economical than generating electricity at the mine mouth or wellhead and transmitting electricity by power transmission line.



(in the year of 2030) (in the year of 2050)

Figure 14 Electricity generation and transmission

Figure 15 shows the time profiles of CO_2 emissions in Asia and the share of cumulative emissions from 2000 to 2050 by sub-region. The figure indicates the three-fold increase in the CO_2 emissions from Asia as a whole within the next five decades. The Chinese sub-region is estimated to be outstandingly the largest source followed by the South Asian sub-region (including India). The amount of CO_2 emitted by Japan is expected to be almost constant over the simulation period. These figures suggest indeed the importance of initiating certain concrete actions for the abatement of CO_2 emissions for this region.

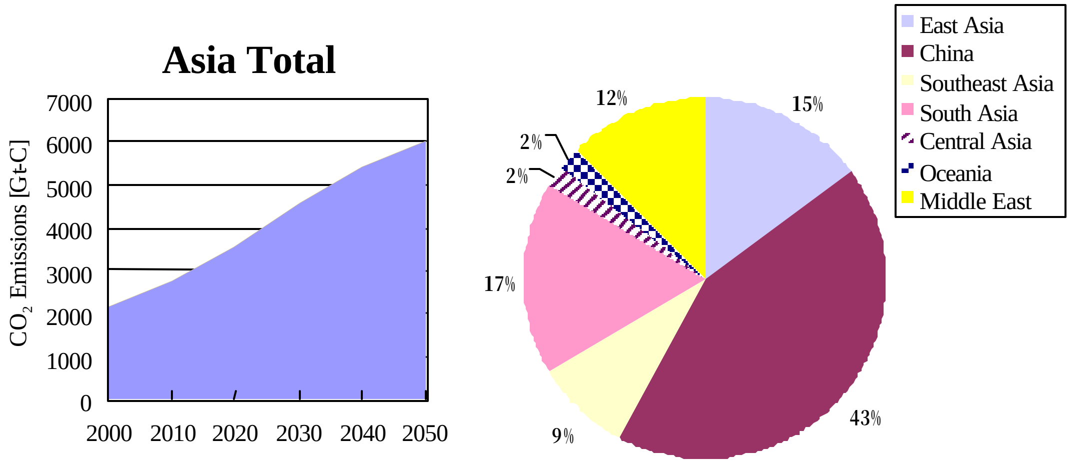


Figure 15 CO_2 emissions from Asia

3.2 INC case

One of the results of the BAU case is that the amount of energy transported expands rapidly, in accordance with the rapid energy demand growth of the Asian countries. However, because this outcome requires a large monetary investment, it is not easy for the developing countries to procure enough money to construct the extensive infrastructure needed. Therefore, here in the INC case, we sought the optimal configuration of energy transportation infrastructure in Asia with the consideration of certain upper limits of investment money for some major developing countries; that is, China, India, and Pakistan. The estimated investments in energy transportation infrastructure in these countries are shown in Figure 16 for the BAU case. The infrastructures taken account of are land transportation infrastructure (oil pipelines, natural gas pipelines, power transmission lines, coal freight trains, and so on), ocean transportation infrastructure (oil tankers, LNG tankers, coal bulk carries, and so on), and other related equipment (liquefaction plants, AC-DC converters, and so on).

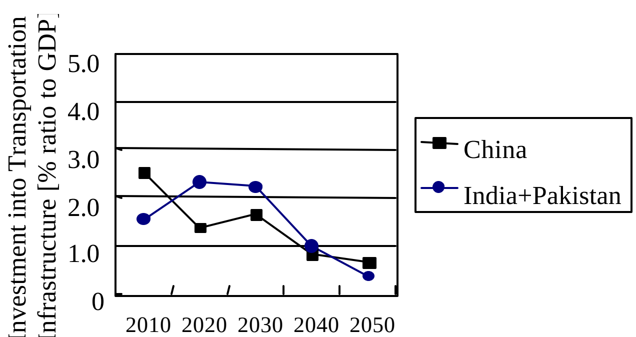


Figure 16 Investment in energy transportation infrastructure in the BAU case

The amounts of infrastructure investment by type in China and India & Pakistan are shown in Figure 17. As the constraints on investment become strict in China and India & Pakistan, the investment in coal freight trains decreases significantly, and the rate of investment in oil pipelines increases.

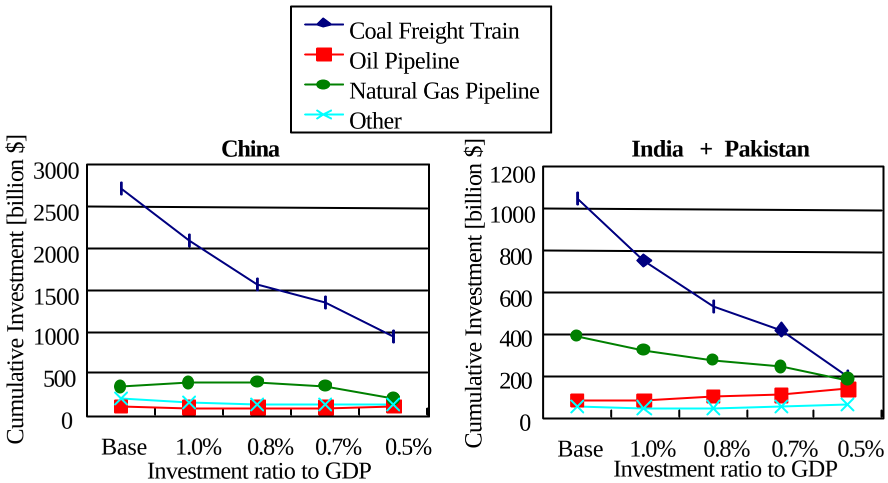


Figure 17 Cumulative investment under different investment constraints

The investment in natural gas pipelines in China decreases when 0.5% of GDP becomes an upper limit of the annual amount of investment into the energy transportation infrastructure. Though investment in natural gas pipelines has been decreasing little by little, investment in oil pipelines is on the increase on one side, and the increase of oil consumption can be seen.
To illustrate the influence of the investment constraint on the optimal energy flow in Asia, here we show the simulation results for the case where an upper limit on the amount of annual investment of 0.7% of GDP was arbitrarily assumed. The state of coal production and transportation in 2050 is shown in Figure 18. When compared with that of the BAU case, the ocean transportation of coal to China varies significantly. Domestic coal production in China and India doesn't catch up due to the lack of transportation infrastructure--i.e. railroad systems--and it is anticipated that the energy systems of these countries will be dependent upon overseas coal.

The state of oil production and transportation is shown in Figure 19. Oil demand in the electric power sectors is estimated to increase both in China and India. The simulation results indicate that although India will expand oil imports mainly from the Middle East, China will do so from Alaska as well as the Middle East.

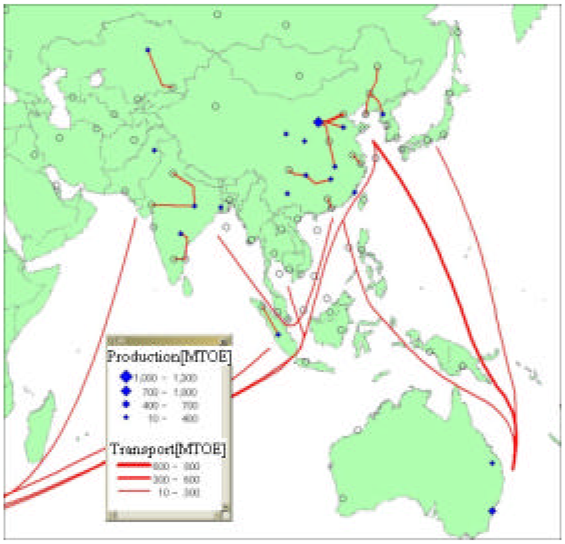


Figure 18 Coal production and transportation in 2050 in the INC case

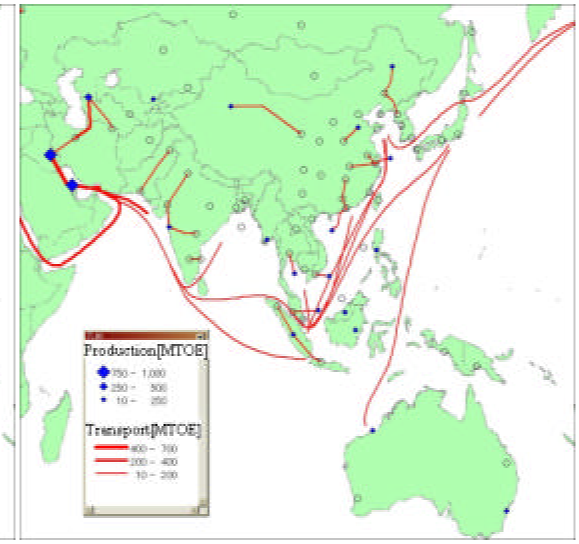


Figure 19 Oil production and transportation in 2050 in the INC case

The state of natural gas production and transportation is shown in Figure 20. Compared with the BAU case, the development of Chinese natural gas pipelines is greatly delayed in the INC case.

The computational result of electric generation and transmission in 2050 is shown in Figure 21. If the investment constraint were to become strict in China, electricity generation by coal-fired power plants would not grow after the year 2020. Electricity generation by oil-fired power plants increases noticeably in comparison with the BAU case, and that by gas-fired power plants in China increases a little.

In the case of India and Pakistan, electricity generation by coal-fired power plants doesn't increase from the beginning, and it decreases greatly in comparison with the BAU case.

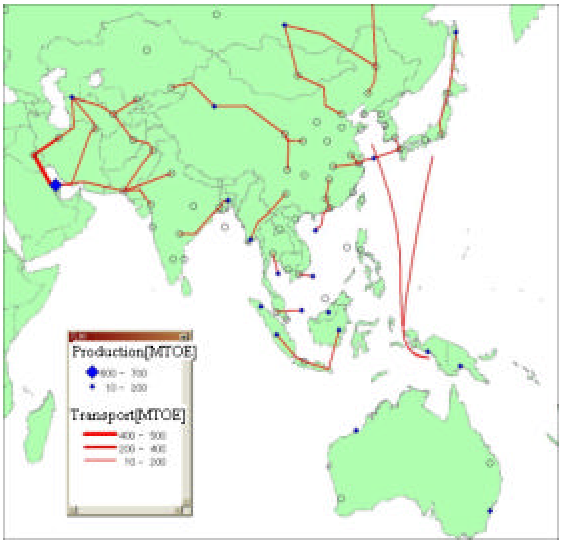


Figure 20 Natural gas production and transportation in 2050 in the INC case

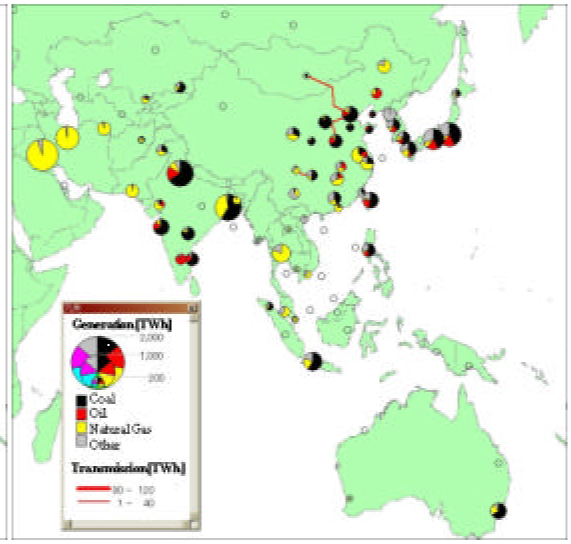


Figure 21 Electricity generation and transmission in 2050 in the INC case

3.3 CTX case

The computational results for energy production and transportation in 2050 are shown in Figures 22 - 25. As compared to the results in the BAU case, coal production is reduced substantially in the CTX case, and coal is replaced by natural gas. The major reduction in coal consumption occurs in the electricity generation sectors in China and India. The carbon tax has practically no effect on the topology of the oil supply infrastructure. Natural gas will get a larger share in the total fossil energy supplies, and its contribution to the electricity generation sector will become enormous over the simulation period. A more extensive pipeline network for natural gas transportation is expected in the western part of India, and the eastern part of China is linked to gas wells in her western territory, as well as those in East Siberia, with long distance natural gas pipelines of much larger capacities. The model takes into account that hydrogen will serve as a substitute fuel for natural gas in the gaseous fuel demand and estimates that the amount of hydrogen consumed in Asia will remain insignificant, even in the CTX case. It should be noted that emerging hydrogen use for fuel cell vehicles was not taken into account in the present model.

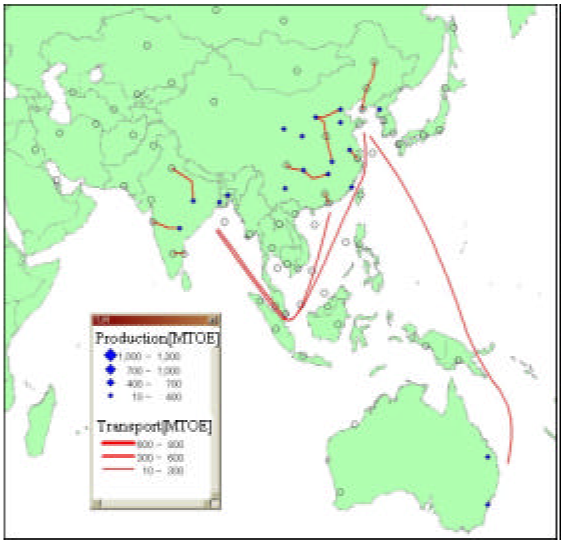


Figure 22 Coal production and transportation in 2050 in the CTX case

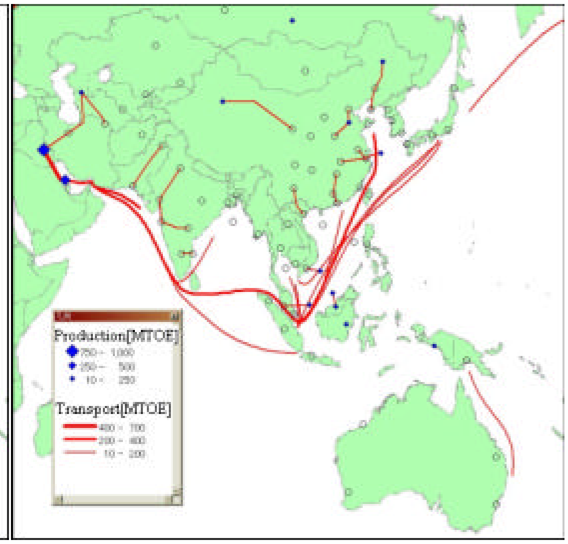


Figure 23 Oil production and transportation in 2050 in the CTX case

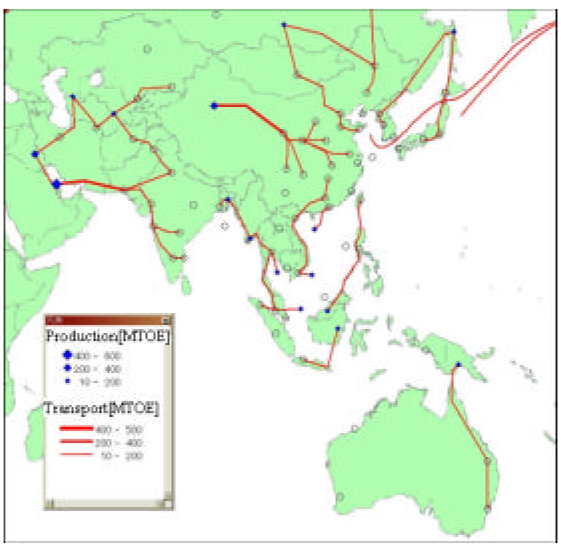


Figure 24 Natural gas production and transportation in 2050 in the CTX case

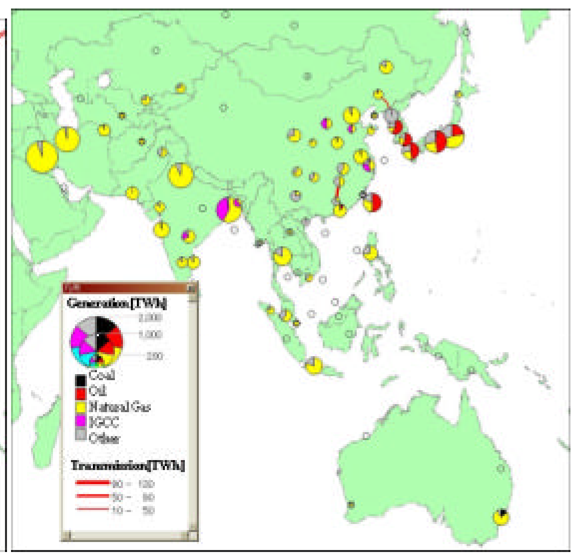


Figure 25 Electricity generation and transmission in 2050 in the CTX case

Figure 26 indicates CO_2 emissions reduction by different carbon tax rates ranging from 100 to 500$/t-C during the period between 2000 and 2050. The higher the rate of carbon taxation, the less CO_2 emitted into the atmosphere. Relations between the rates of carbon taxation and the rates of CO_2 emissions reduction are also shown in Figure 26. The decrease in the gross emissions of CO_2 is achieved by changes in the mix of electricity generation. Figure 27 indicates the total abatement cost for CO_2 emissions reduction. The abatement costs are defined as the difference between the total energy system costs in the CTX case and those in the BAU case. The total abatement cost rises exponentially, as the CO_2 emissions reduction grows big.

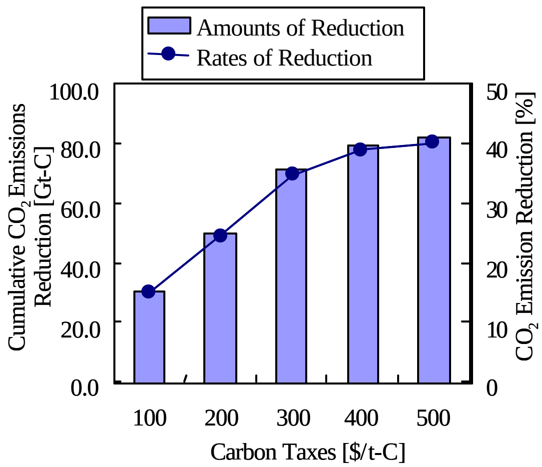


Figure 26 CO_2 emissions reduction by different carbon taxes

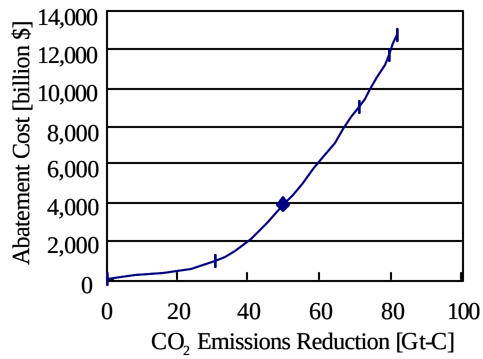


Figure 27 CO_2 emissions reduction and the abatement cost

Figure 28 shows the calculated flows of recovered CO_2 between 2000 and 2050 with a carbon tax of 300 US$/t-C. The simulation result indicates that ocean sequestration of CO_2 is expected to play an important role in the areas, such as Japan and South Korea, in which there is little storage capacity for CO_2 subterranean sequestration. On the other hand, in China and India, CO_2 pipeline transportation and subterranean sequestration can be seen. Please note that the positions of the dark triangles at the coastal nodes in the figure indicate the seaports of CO_2 shipment, but not those of sequestration sites. The ocean sequestration sites are not indicated in Figure 28.

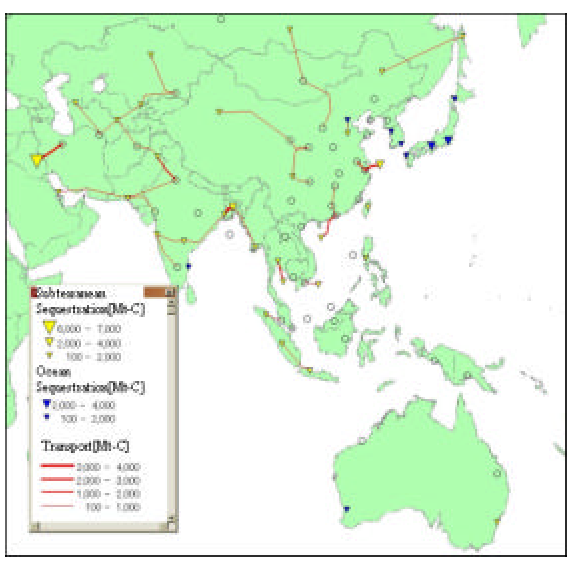


Figure 28

4. Concluding remarks

The purpose of this study was to obtain insights into the possible future configuration and operation of energy and CO_2-related infrastructure in Asia and Eurasia, where energy demands are rapidly growing. This paper presented the outline of the energy system model built in the study and showed part of the results obtained. Bearing in mind the considerable uncertainties as to various assumptions made in the model, the results of the model simulation can be tentatively summarized as follows:

(1) In the BAU case, coal is the dominant primary energy source, especially for power generation in most Asian countries, and natural gas becomes the second most important primary energy source. Most of the oil requirements in the Asia and Eurasia region will continue to be provided almost exclusively by the Middle East.

(2) The results indicate that transporting those fuels by rail or pipeline and generating electricity close to the energy consuming cities is generally more economical than generating electricity at the mine mouth or wellhead and transmitting electricity by power transmission line.

(3) The development of gas production and transportation infrastructures appears as a robust energy supply option for Asian countries. An increased reliance on natural gas would provide Asian countries with more geographically diversified energy supply structures, thus improving the security of their energy procurement.

(4) It is not obvious that the development of region-wide electricity grids among Asian countries is necessary. However, in some cases, we can find a few inter-city routes of power transmission that are optimal solutions of the model.

(5) Investment constraints on energy transportation infrastructure in some Asian countries may lower the use of their domestic coal and raise their degree of dependence on oil and natural gas, as well as on coal imported from overseas countries.

(6) In the CTX case, the model estimated that an extensive network of natural gas pipelines would be developed in China and East Asia. Neither investment constraints nor carbon taxes seem to have a significant influence on the optimal configuration of region-wide electricity grids.

(7) It seems unlikely that the electric power systems of Japan will be linked with those of neighboring countries, mainly because of the economic advantages of doing so are poor. When it comes to regional energy grids, Japan may have to give priority to international natural gas pipelines.

This study of model analysis is continuing, and the following research topics will be incorporated in our future studies:

- Further improvement of the accuracy of the data on fossil fuel resources and production costs;
- sensitivity analyses of future energy demand scenarios;
- extension of the energy system model, described in this paper, to include various non-fossil fuels; and
- consideration of nonlinear effects of infrastructure, such as economies-of-scale.

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