ELECTRIC POWER GRID INTERCONNECTIONS IN NORTHEAST ASIA

A QUANTITATIVE ANALYSIS OF ECONOMIC AND ENVIRONMENTAL BENEFITS

ASIA PACIFIC ENERGY RESEARCH CENTRE

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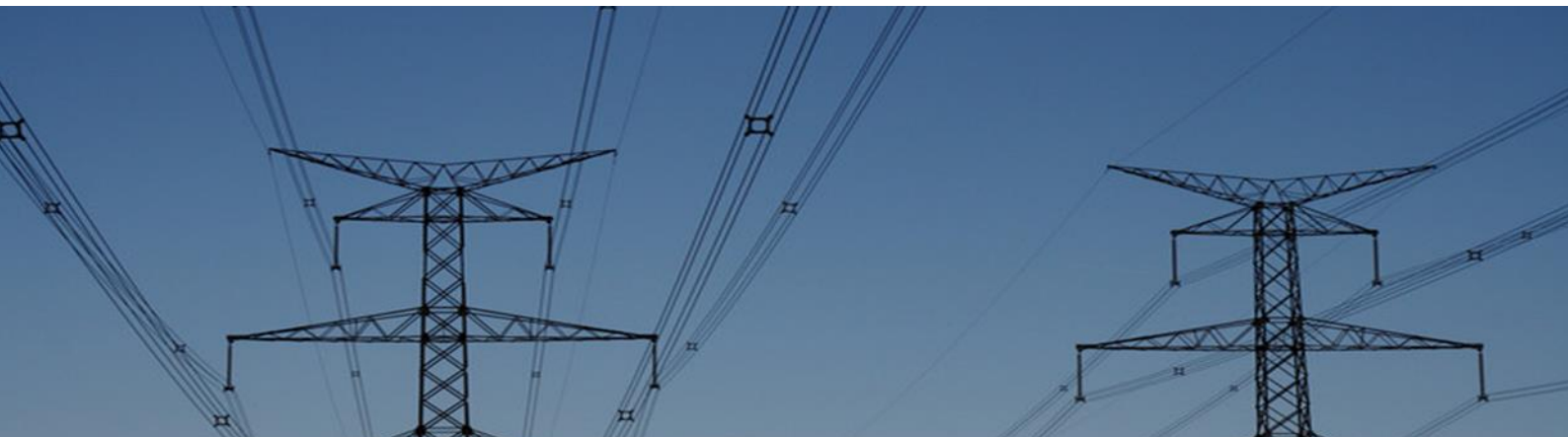

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FOREWORD

Following the Asia-Pacific Economic Cooperation's mission of promoting economic prosperity in a sustainable way, this research document performs a quantitative analysis of opportunities and challenges of electric power grid interconnections in Northeast Asia (NEA) with a focus on renewable energy utilisation.

The new energy situations created by a number of recent natural and economic events, including serious air pollution issues in China, nuclear disasters in Japan and power shortage and rolling blackout in Korea, require a review of the previous priorities of the energy policies. This background made power grid interconnection more attractive in NEA as a means to build an economically efficient power system and to effectively utilize renewable energy in the region. Quantitative examinations and discussions of these potential benefits are the backbone of this research document.

Besides the analysis, this document also summarises recent power market situation as well as grid interconnection proposals over the last two decades, in order to deliver comprehensive information to policy makers.

I would like to thank the experts who have provided their knowledge to this document, the feedback gained through workshops, academic and professional events and peer-review processes has greatly enriched the outcomes presented. As an independent research project, however, the contents herein reflect only APERC's view and might change in the meantime depending on drastic external events or changes in the energy and policy agendas of particular economies.

This report is the work of the Asia Pacific Energy Research Centre. It is an independent study, does not necessarily reflect the view of or policies of the APEC Energy Working Group or individual member economies. Hopefully, this research document will become a cornerstone of the establishment of information exchange and international collaborative activities for leveraging APEC's economic and cooperative strengths.

Takato OJIMI
President
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November 2015

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LIST OF ABBREVIATIONS

AC	Alternating Current
AAGR	Average Annual Growth Rate
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
ASG	Asian super grid
bbl	Barrel
DC	Direct Current
DH	District Heating
DPRK	Democratic People's Republic of Korea
EBRD	European Bank for Reconstruction and Development
EDMC	The Energy Data and Modelling Center, The Institute of Energy Economics, Japan
EENS	Expected Energy Not Supplied
EHV	Extra High Voltage
EIA	Energy Information Administration, US Department of Energy
ESCJ	Electric Power System Council of Japan
ESI SB RAS	Melentiev Energy Systems Institute, Siberian Branch of The Russian Academy of Science, Russia
FEEC	Far Eastern Energy Company
FEPC	Federation of Electric Power Companies of Japan
FGC UES	Federal Grid Company of Unified Energy System (Russia)
F/S	Feasibility Study
GAMS	General Algebraic Modeling System
Gt-CO_2	Gigaton-CO_2
GW	Gigawatt
GWh	Gigawatt-hour
HAPUA	The Heads of ASEAN Power Utilities / Authorities
HV	High Voltage
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current

IEA	International Energy Agency
IPS	Integrated Power System
JAIF	Japan Atomic Industrial Forum
JEPIC	Japan Electric Power Information Center
JREF	Japan Renewable Energy Foundation
KEEI	Korea Energy Economics Institute
KEPCO	Korea Electric Power Corporation
KERI	Korea Electrotechnology Research Institute
KESIS	Korea Energy Statistics Information System
kW	Kilowatt
kWh	Kilowatt-hour
LHV	Lower Heating Value
LOLE	Loss of Load Expectation
MEPI	Ministry of Electric Power Industry (China)
METI	Ministry of Economy, Trade and Industry (Japan)
MKE	Ministry of Knowledge Economy (Korea)
MMBtu	Million British Thermal Unit
MOTIE	Ministry of Trade, Industry and Energy (Korea)
MOU	Memorandum of Understanding
Mt-CO_2	Megaton-CO_2
MUFJ	Bank of Tokyo-Mitsubishi UFJ
MW	Megawatt
MWh	Megawatt-hour
NEA	Northeast Asia
NEAREST	Northeast Asian Electrical System Ties
NREL	National Renewable Energy Laboratory (US)
O&M	Operation and Maintenance
OCCTO	Organization for Cross-regional Coordination of Transmission Operators (Japan)
PPS	Power Producer and Supplier
PV	Photovoltaics
R&D	Research and Development

RITE	Research Institute of Innovative Technology for the Earth (Japan)
SGCC	State Grid Corporation of China
Skoltech	Skolkovo Institute of Science and Technology (Russia)
SO UPS	System Operator of the United Power System of Russia
TSUC	Total Supply Unit Cost
TW	Terawatt
TWh	Terawatt-hour
UHV	Ultra High Voltage
USD	US Dollar
WAEC	Weighted Average Electricity Charge
WGC	Wholesale Generation Company (Russia)

EXECUTIVE SUMMARY

Several recent regional events, including the nuclear disaster in Japan, the power shortage and rolling blackouts in Korea, and increased concern regarding air pollution in China, have made power grid interconnections potentially more attractive. Several organisations have proposed power grid interconnection concepts, i.e., Asia Super Grid and *Gobitec*, with a focus on developing the abundant renewable resources in the Gobi Desert and Eastern Russia and on building a more resilient and economically efficient power system. These concepts are still at the discussion stage; therefore, in order to deliver comprehensive information for policy making and to advance the negotiations, this report focuses on the following points:

- Overview of power grids in Northeast Asia (NEA) economies (Section 2);
- Major concepts of power grid interconnection in NEA (Section 3); and
- Modelling and analysis of economic and environmental benefits of grid interconnections (Section 4).

Quantitative examinations and discussions of potential benefits are the backbone of this research document. Through our research, following findings are obtained from our simulation analysis.

A coordinating organisation is necessary to draw up a blueprint for NEA-wide interconnections.

Various interconnection concepts have been proposed by private companies and research institutes; however, there is limited coordination by economy's authorities or international/regional organisations in NEA (such as the Heads of ASEAN Power Utilities / Authorities (HAPUA) in the ASEAN region). In order to draw up a detailed blueprint for NEA-wide interconnections as well as to research, discuss and implement the concepts in an effective manner, a coordinating entity should be established.

Modest economic benefits are likely to be a major challenge for implementation.

Our simulation analysis shows that interconnections contribute significantly to fuel cost savings by shifting to cheaper fossil fuel or to renewables. However, total system cost reductions appear modest because of the large initial investments needed in developing the renewables and transmission lines. The limited total cost savings are likely to pose an implementation challenge for NEA grid interconnections. This result suggests that grid interconnections become more economically attractive in higher fuel price or lower initial cost situations, and *vice versa*. The relevant planning organisations should carefully consider the future fuel price and initial cost trends when considering how to interconnect power grids in an economical manner. This

study also shows that the economic benefits expand with higher carbon prices. Regional carbon market and emission reduction regulations are important for implementing power grid interconnections.

Grid interconnection in NEA should be in tandem with renewable energy developments.

Access to wind and solar resources in the Gobi Desert and additional hydro resources in Eastern Russia promotes an environmentally-friendly generation mix with. On the other hand, cost-optimal grid interconnections without renewable energy development would promote low-cost coal-fired generation in China and Russia, resulting in an emissions increase in NEA and potentially worsening air pollution in China. Thus, interconnection projects should be undertaken with renewable energy expansion in order to reap both economic and environmental benefits.

Unexploited hydropower in Eastern Russia would be the driver of opportunities for Russia and neighbouring regions.

Our study implies that additional hydropower developments stimulate the scale of interconnection between Eastern Russia and neighbouring regions. Historically, electric utilities and transmission companies in Russia, in cooperation with organizations in neighbouring economies, have been exploring the possibilities of cross-border connection. As the costs for hydro generation largely depend on site-specific characteristics, the relevant planning organisations should assess the unexploited hydropower potential, which can be economically developed for export.

The planning organisations should carefully discuss the economic viability before implementation.

The findings above imply the modest economic benefits and barriers due to uncertainties in future fuel prices, initial costs and carbon prices. Given the oil and Asian LNG deflation after mid-2014 as well as no regional emissions regulations in NEA, grid interconnection would face economic challenges. Our modelling approach also includes several simplifications that should be addressed in future work (Section 5). The planning organisations need to carefully discuss the economic viability in a more detailed manner considering site specific conditions, before stepping forward and implementing the project.

1. INTRODUCTION

Over the past two decades, electric power grid interconnections have gained attention in Northeast Asia (NEA), an area that we define as four Asia-Pacific Economic Cooperation (APEC) economies--China, Japan, the Republic of Korea (Korea), and Russia-- and two non-APEC economies--Mongolia and the Democratic People's Republic of Korea (DPRK). Various interconnection schemes have been proposed for NEA (Streets, 2003; Yun & Zhang, 2005; Hata, 2005; Hippel, et al., 2011). Yet, while technically feasible (KEPCO, 2014a), these cooperative proposals have been hampered by factors such as existing national policies of energy self-sufficiency and the sometimes-volatile diplomatic and political situation in the region. Thus, the only existing cross-border power cooperation projects are small in scale, linking Russia to Mongolia, Russia to China, and China to the DPRK (Table 1).

Table 1 Major existing cross-border interconnections, Northeast Asia

Transmission Line Component	Voltage [kV]
Gusinoozerskaya GRES (Russia) – Darkhan (Mongolia)	220
Kharanorskay GRES (Russia) – Choibalsan (Mongolia)	110
Chadan (Russia) – Khandagaity – Ulanngom (Mongolia)	110
Blagoveshensk (Russia) – Heihe (China)	220/110
Sivaki (Russia) – Sirius /Aigun (China)	110
Blagoveshensk (Russia) – Sirius /Aigun (China)	2*220
Amurskay (Russia) – Heihe (China)	500

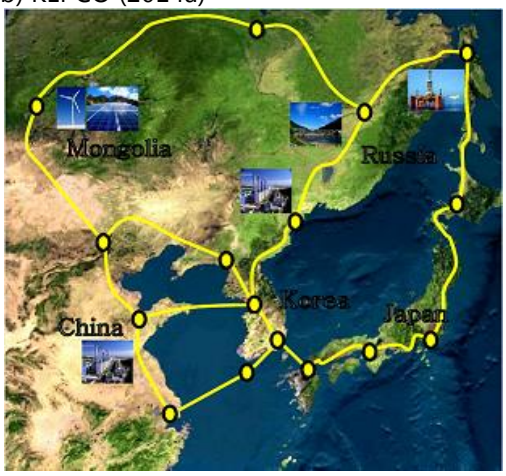
Source: Podkovalnikov (2002)

However, several recent regional events have made regional power interconnections potentially more attractive. The Great Earthquake and nuclear disaster in Japan (March, 2011) pushed the economy to focus more on resilient power system and renewable energy. The power shortages and rolling blackouts in Korea (September, 2011) highlighted the vulnerabilities of its power system. Air pollution issues in China, largely attributed to coal-dependent power sector, has become an increasingly important concern. Meeting these economies' electricity demand with a cleaner and more reliable power system has become a major challenge; thus, several organisations have proposed multilateral power grid interconnection concepts, i.e., Gobitec and Asian Super Grid—interconnecting power grids and effectively utilising the abundant renewable energy resources in the Gobi Desert and Eastern Russia—as illustrated in Figure 1 (Energy Charter, et al., 2014; KEPCO, 2014a). The wind and PV potential in Mongolia has been estimated at 1100GW and 1500GW, respectively (Elliott, et al., 2001; Energy Charter, et al., 2014), and economically feasible hydropower potential in Eastern Russia is estimated at 690TWh/year (estimated by European Bank for Reconstruction and Development, see IEA (2003)).

Figure 1 Power grid interconnection concept (examples)

a) Energy Charter, et al. (2014)

b) KEPCO (2014a)



Source: Energy Charter, et al. (2014) and KEPCO (2014a)
Note: Each figure is reproduced as Figure 31a) and Figure 32, respectively.

There have been some previous economic analyses on connecting power grids in various parts of the world: Southern Africa is the focus of Bowen, et al. (1999), Europe of Lilliestam & Ellenbeck (2011) and Schaber, et al. (2012) and Southeast Asia of Chang & Li (2013) and Matsuo, et al. (2015). Among those studies, Schaber, et al. (2012) conducted a detailed analysis on the impacts of grid interconnections on regional renewable energy utilization. They employed a Europe-wide power system model with a detailed temporal resolution (hourly time slice for six representative weeks), which appropriately reproduce the actual power generation, electricity prices and cross-border power transportation.

Economics of power grid interconnection in the NEA region has been investigated. Cost-benefits analyses of grid interconnection scenarios in NEA were performed by Hippel (2001), Podkovalnikov (2002), Lee, et al. (2005), Chung & Kim (2007), Energy Charter, et al. (2014) and Chudinova, et al. (2015). Analyses on power system reliability were conducted by Choi, et al. (2006) and Yoon (2007). Yet, to our knowledge, few studies have focused on the whole of NEA and analysed the impacts of grid interconnections with a focus on renewables both in the Gobi Desert and Eastern Russia considering power systems particulars (e.g. load curves, generation dispatch). Except for Energy Charter, et al. (2014) and Chudinova, et al. (2015), the studies listed above covered only a part of NEA (three to four out of the six economies) and did not consider renewable energy in the Gobi Desert. Chudinova, et al. (2015) does not take into account renewables in the Gobi Desert, either. As for Energy Charter, et al, (2014), they proposed to install 50GW of wind and 50GW of solar photovoltaics (PV) in the Gobi Desert, and estimated the supply costs to other NEA economies. However, their cost assessment did not consider regional power system particulars, such as the load curve of the importing economies and the seasonal and diurnal output variation of the solar and wind power from the Gobi Desert.

Thus, we developed a multi-region power system model, which covers the whole of NEA, in order to quantitatively evaluate the potential benefits of, and barriers to, power grid interconnection and expansion of renewable energy for export. The model seeks to minimize overall system cost, considering seasonal and daily characteristics of electric load of each region and output patterns of renewables in the Gobi Desert. We analyse following points with the model:

- the potential economic benefits (total costs, marginal generating costs and so on) for the entire NEA region and for each economy;
- the potential CO_2 reductions by sharing renewable resources in the NEA; and
- the optimal generation mix and cross-border power flow considering representative hourly/daily load curves for each season.

We believe that our analysis contributes to understanding of the costs and benefits of the grid interconnection and large-scale renewable energy utilization in NEA from a systems viewpoint. However, it is important to note that this work mainly focuses on economic analyses. Other important factors, such as technical challenges, geopolitical obstacles or law harmonisation, are beyond our research scope. These topics should thus be explored in the future research.

This report consists of five sections. First, the objective and scope of this study are briefly explained in this section. Section 2 details the characteristics of power grids in the major NEA economies and introduces the stakeholders in each region. Next, Section 3 summarises the major proposals and recent activities/progresses of grid interconnections. Section 4, which provides the modelling and analysis of power grid interconnection, is the main part of this report. This section discusses our model structure, assumptions and simulation results. Finally, the major findings and policy implications derived from this study are listed in Section 5.

2.OVERVIEW OF POWER GRIDS IN APEC NORTHEAST ASIA

Electricity market varies from economy to economy in APEC NEA. This section summarises the recent situation of each economy's electricity sector, including transmission line networks, generation mix, electricity tariffs, future development plans and so on. Section 2.5 briefly compares the major indicators across NEA.

2.1. CHINA

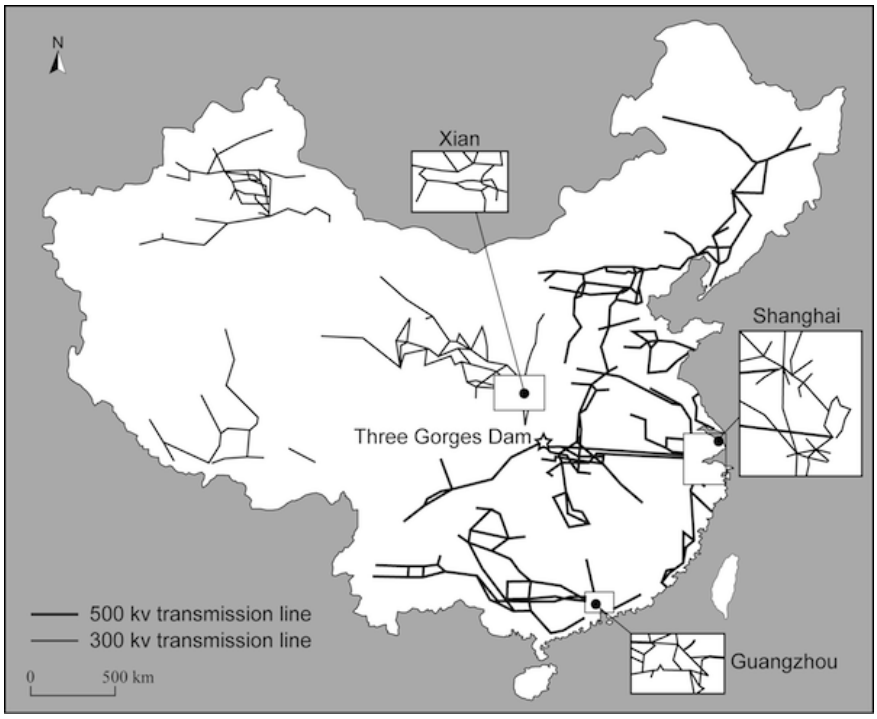
2.1.1. ELECTRICITY MARKET AND POWER GRID

China has seven power grids (Figure 2). The State Grid Corporation of China (SGCC) owns the Northeast, North China, Central China, East China, Northwest and the Tibet power grids, whereas the China Southern Power Grid Company covers the South China power grid. The grids' frequency is 50Hz. Figure 3 describes China's transmission line network (500kV and 300kV). China has been accelerating high-voltage (HV) grid interconnections among its domestic power grids to resolve regional demand–supply imbalances and transmit electricity from resource-abundant regions (central/west area) to 'energy hungry' regions (east coastal area).

Figure 2 Power grids, China

Source: Xu & Alleyne (2012).
Note: The original figure included Chinese Taipei; we have edited the map to exclude this area.

Figure 3 500kV and 300kV transmission line networks, China



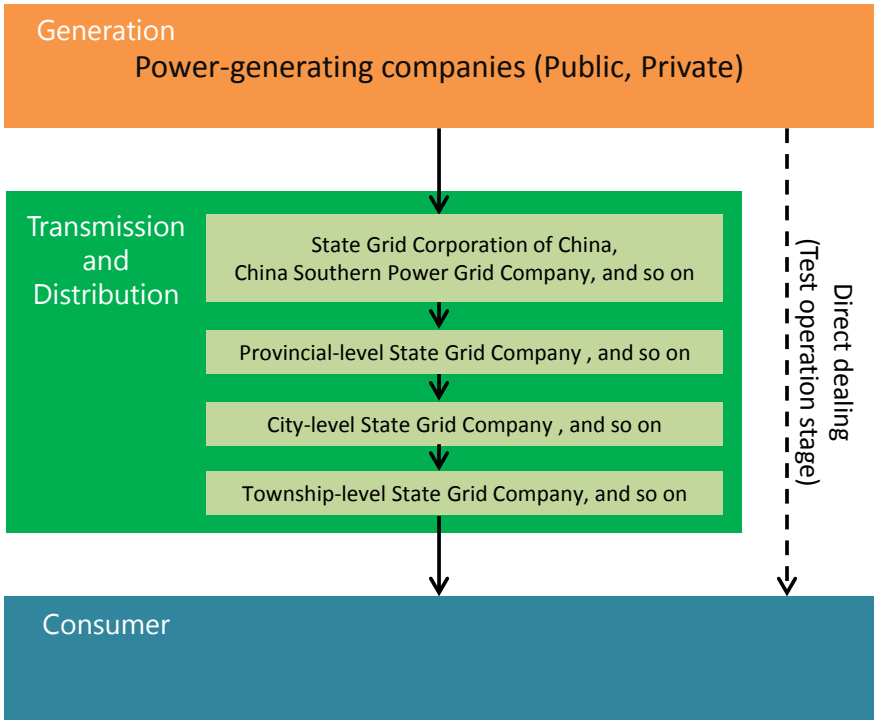
Source: Cartier (2013).
Note: China has recently been constructing ultra-high-voltage transmission lines. According to JEPIC (2014a), 1000kV and 800kV transmission line extent amounted to approximately 6105km in 2012.

China's electricity industry has been centrally run by the state since the creation of the People's Republic of China in 1949. Power-generation assets were assigned to and operated by various state-owned enterprises, which are placed under the administrative supervision of the Ministry of Electric Power Industry (MEPI) (Gee, et al., 2007). In 1986, China began reforming its power sector in three phases. In the first phase (1986–97), in order to solve power shortage issues and meet surging demand, the central government allowed provincial and local governments as well as private companies to build and operate power-generation facilities. In the second phase, MEPI's assets were transferred to the newly established State Electric Power Corporation in 1997; moreover, MEPI was abolished and its administrative functions were transferred to the Electric Power Department of the State Economic and Trade Commission (SETC) in 1998. Then, in the final phase in 2002, the State Council of the China unbundled power generation and transmission/distribution. The State Electric Power Corporation was divided into two state grid corporations (SGCC and China Southern Power Grid Company), five power-generation companies, and four power service companies (Gee, et al., 2007).

In China, generated electricity is supplied through SGCC/China Southern Power Grid Company and through Provincial-level, City-level and Township-level grid companies (Figure 4). China has interconnections with several neighbouring foreign countries/economies, including DPRK, Kyrgyzstan, Mongolia, Southeast Asian

counties and Russia. In the NEA region, China imported 2.6TWh of electricity from Russia in 2012, and in 2013, this expanded to 3.5TWh, accounting for approximately half of total imports.

Figure 4 Electricity supply system, China



Source: JEPIC (2014b).

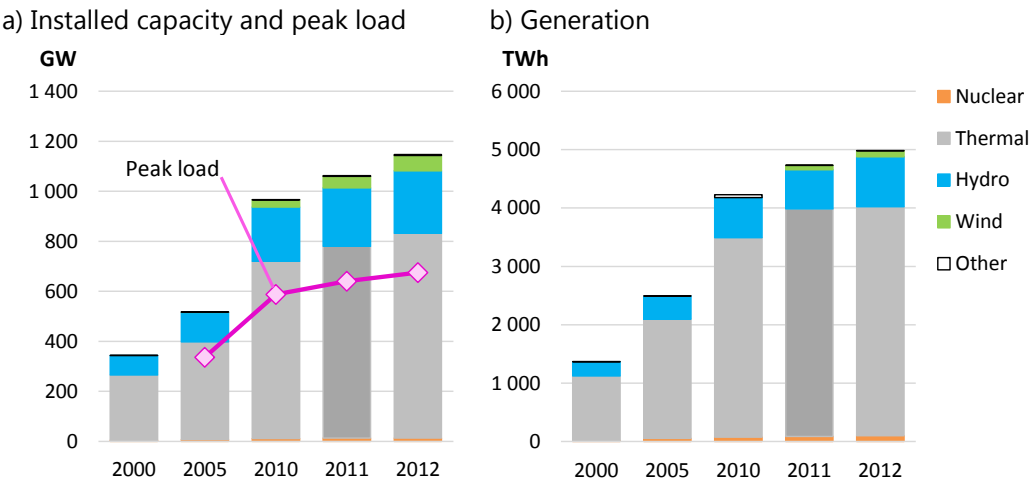
2.1.2. ELECTRICITY DEMAND AND SUPPLY

In 2012, China's power-generation capacity reached 1 150GW (Figure 5), which was seven times and three times larger than that in 1990 and 2000, respectively. Over the last decade, thermal power-generation facilities recorded the largest growth in terms of capacity, increasing by approximately 560GW from 2000 to 2012, whereas nuclear power-generation facilities increased by approximately 8GW and hydro power-generation facilities by approximately 170GW. Coal-fired power-generation holds the largest share (66%) in total capacity in China, with an expected average annual growth rate (AAGR) of 7.8% from 2010 to 2015 (Section 2.1.3). Concerning the power-generation mix, thermal power plants account for 78% and hydro power plants for 17% of the mix. In 2012, nuclear power plants accounted for approximately 1% and 2% shares in capacity and generation mix, respectively.

Among all the renewable power-generation facilities, wind power capacity showed remarkable growth at an AAGR of more than 40% from 2005 to 2012. According to JEPIC (2014a), its capacity increased to more than 60GW by 2012; however, its share in total generation was not more than 2.1% mainly because of lower capacity factor than dispatchable generation as well as of grid access limitation issues.

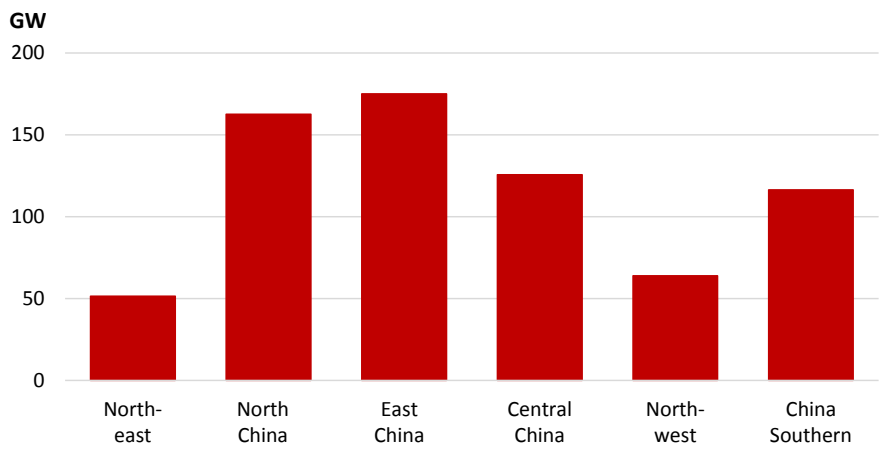
The scale of China's power grid varies from grid to grid (Figure 6). As explained in Section 4, the definition of NEA in this study includes both the Northeast and North China grids. The Northeast grid has the smallest peak load (52GW) among the power grids denoted in the figure: it is approximately one-third of the East China grid's peak load (175GW). The North China grid, which covers the Beijing area, has the second largest peak load (163GW).

Figure 5 Historical power-generation capacity, peak load and generation, China



Sources: JEPIC (2004; 2007; 2012; 2013).
Note: Historical peak load data for 2000 was not available in the source document.

Figure 6 Peak load by power grid, China, 2012



Source: JEPIC (2014a).

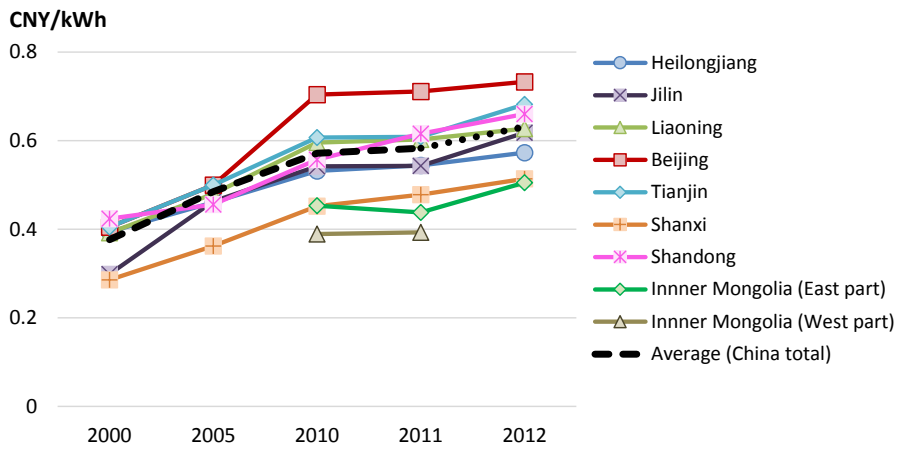
According to RITE (2014), the average efficiency of China's thermal power plants between 2009 and 2011 was 36.8% (at the generation end, on a lower-heating-value (LHV) basis), which is lower than the global average by 2.0 points. The average efficiency of coal-fired plants for these three years was 35.6%. RITE (2014) reported

that the efficiency of coal-fired plants in China showed a gradual improving trend, especially after 2005, and became higher than the global average efficiency of such plants in 2012 (35.2%).

Figure 7 shows historical average electricity prices in China and in major provinces/cities in the northeast area. The price in each Chinese province is regulated by the government. The government applies lower prices to the economically underdeveloped provinces (for example, Inner Mongolia). These regulated prices do not reflect market mechanisms, and the low prices have continuously caused power companies to experience deficits.

Electricity prices show increasing trends over the last decade. They have risen by 4% from 2000 to 2011, and the average price in 2011 was 0.583 CNY/kWh. Among the provinces/cities in Figure 7, the 2011 prices ranged from 0.393 CNY/kWh (western part of Inner Mongolia Autonomous Region) to 0.711 CNY/kWh (Beijing). Beijing's price is approximately 1.8 times higher than that in the western part of Inner Mongolia.

Figure 7 Historical average electricity prices, China and major provinces/cities in northeast area



Sources: JEPIC (2004; 2007; 2012; 2014a) and SERC (2010).
Note: The 'China total' price in 2000 is the average of the State Electric Power Corporation area. The Average prices in 2012 are estimated by the average price in State Grid Corporation area, the average price in China Southern Power Grid Company area and the generated electricity in each area in 2012. Due to data availability constraints, only 2010–2012 prices for Inner Mongolia (west part) and 2010–2011 for Inner Mongolia (east part) are included.

2.1.3. ECONOMY'S ENERGY PLAN

The 12th Five-Year Plan for National Economic and Social Development (the 12th Five-Year Plan) is China's latest five-year plan (The State Council of the PR China, 2011). As of Sep-2015, the 13th plan is under discussion. The 12th plan was endorsed by the National People's Congress on 14 March 2011. This five-year plan clarifies the national strategic intent, the government's focus and the people's common program

of action during the five-year period starting in 2011 (APERC, 2013a). With regards to energy development, the plan's focus includes nuclear power, renewable and power grid development as follows:

- Nuclear power: China will accelerate nuclear power development in the coastal provinces, continuously develop nuclear power plants in inland areas and start construction of 40GW nuclear power plants[1].

- Hydro power: China will construct large-scale hydro power plants in the prioritised areas, including Chin-sha River and Dadu River, and start hydro plant construction with a total capacity of 120GW.

- Wind power: China will construct large-scale wind farms (six onshore and two offshore). Newly added capacity will be more than 70GW.

- Solar power: China will deploy 5GW solar power plants, prioritising Tibet Autonomous Region, Inner Mongolia Autonomous Region, Gansu Province, Ningxia Hui Autonomous Region, Qinghai Province, Xinjiang Uyghur Autonomous Region, Yunnan Province and so on.

- Power grid: China will construct more than 200,000km of transmission lines (>330kV).

The plan also mentions a five-year power development plan as summarised in Table 2. Total capacity will increase by approximately 520GW from 2010 to 2015 (at a 9% AAGR). The plan indicates China's intention to promote clean power sources, including wind (26.4% AAGR), solar (89.5%) and nuclear (29.9%). However, coal-fired plants are expected to grow most quickly in terms of absolute capacity: approximately an additional 300GW is expected during the period.

Table 2 Power development targets, 12th Five-Year Plan, China

	2010	2015	AAGR
Total Capacity [hundred million kW]	**9.7**	**14.9**	**9.0%**
Coal-fired [hundred million kW]	6.6	9.6	7.8%
Hydro [million kW]	2.2	2.9	2.7%
Nuclear [million kW]	10.82	40	29.9%
Gas-fired [million kW]	26.42	56	16.2%
Wind [million kW]	31	100	26.4%
Solar [million kW]	0.86	2.1	89.5%

Source: The State Council of the PR China (2011).

[1] Note that the 12th Five-Year Plan was approved merely three days after the Fukushima Daiichi nuclear power plant accident, and some delays or readjustments to the plan might occur in the future.

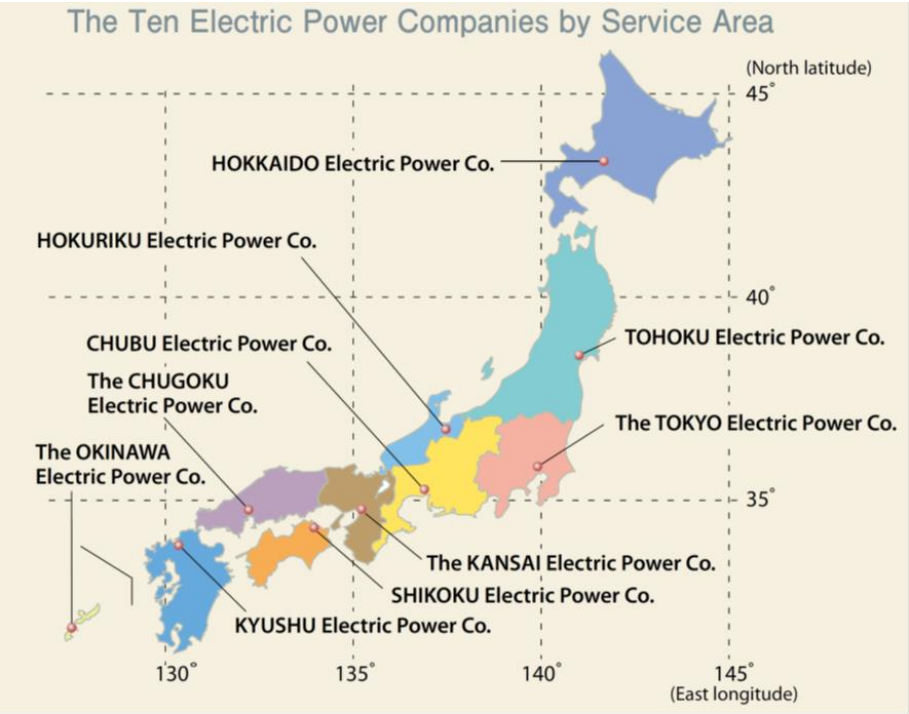
2.2. JAPAN

2.2.1. ELECTRICITY MARKET AND POWER GRID

Japan has ten electricity service areas, each traditionally dominated by a vertically integrated private utility. Each utility is responsible for ensuring a stable power supply in each service area and has developed and managed a self-sufficient power supply system. As depicted in Figure 8 and Figure 9, the frequency in east Japan (Hokkaido, Tohoku and Tokyo area) is 50Hz, whereas it is 60Hz in west Japan. Three frequency converter (FC) stations (Sakuma, Shin-shinano and Higashi-shimizu) with a total capacity of 1200MW have been installed to connect east and west Japan.

Japan's electricity market has been partially liberalised to ensure fair competition and transparency. The Electricity Business Act amended in 1995 allows independent power producers (IPPs) to participate in the electricity wholesale market; subsequently, the 1999 amendment (enforced from March 2000) liberalised the market for extra-high voltage (EHV) consumers (more than 2MW) and allowed power producers and suppliers (PPSs)[2] to sell electricity to the partially liberalised market.

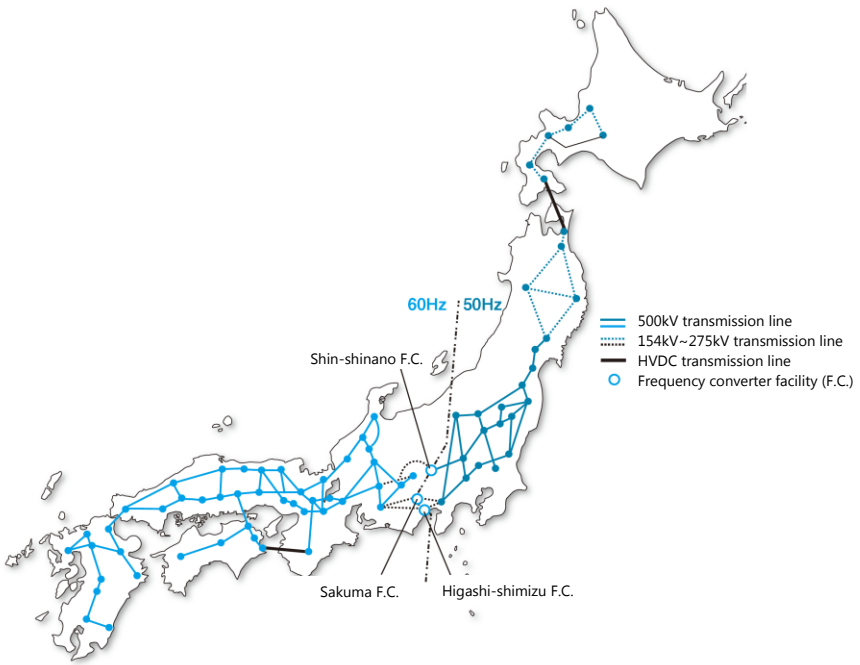
Figure 8 Electricity service areas, Japan



Source: FEPC (2012).

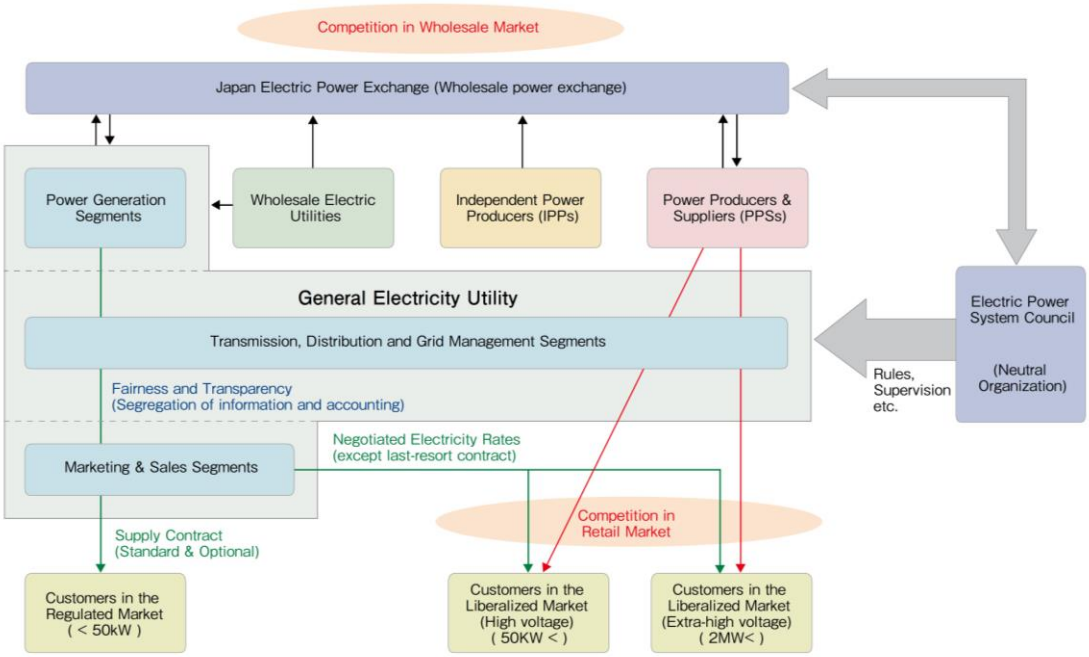
[2] IPSs are allowed to participate in the electricity wholesale market. In contrast, PPSs are allowed to sell electricity to consumers in the liberalized market (≥50kW) using general electric utilities' transmission lines.

Figure 9 Transmission line network (above 154kV), Japan



Source: Imaizumi (2012).

Figure 10 Electricity supply system, Japan, after April 2005



Source: FEPC (2014a).

The amendment in 2003 expanded the scope of liberalisation: the market for consumers requiring more than 50kW was liberalised in April 2004 (FEPC, 2014a). As of April 2015, the liberalised market accounts for approximately 60% of Japan's total electricity demand[3]. Japan Electric Power Exchange (JEPX) was established in 2003 and commenced power exchange from April 2005. Furthermore, to support fair and transparent transmission and distribution operations, the Electric Power System Council of Japan (ESCJ) was established in 2004 and started operations in April 2005. ESCJ's duties include rule-making, dispute resolution, coordination of load-dispatching operations and so on. (ESCJ, 2013). Figure 10 shows the electricity supply systems from April 2005.

After the Great East Japan Earthquake in March 2011 and the subsequent Fukushima Daiichi nuclear power plant accident, the Japanese power industry faces mounting pressure to fully deregulate the electricity market to realise competitive and more transparent electricity supply. The Electricity Business Act was amended in 2013, 2014 and 2015 to reform electricity system. This reform focuses mainly on three stages as follows (METI, 2015a): 1) Establishment of the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) in April 2015[4]; 2) full power retail liberalisation from April 2016; and 3) legal unbundling of the transmission and distribution sector from 2020 and transition to full liberalisation of retail electricity price after the unbundling. In order to avoid a monopoly situation after retail liberalisation in 2016, retail tariffs of designated utilities will be regulated as a transitional measure, and then gradually deregulated after legal unbundling. Amendments to the Electricity Business Act for the three stages were enacted in November 2013, June 2014 and June 2015.

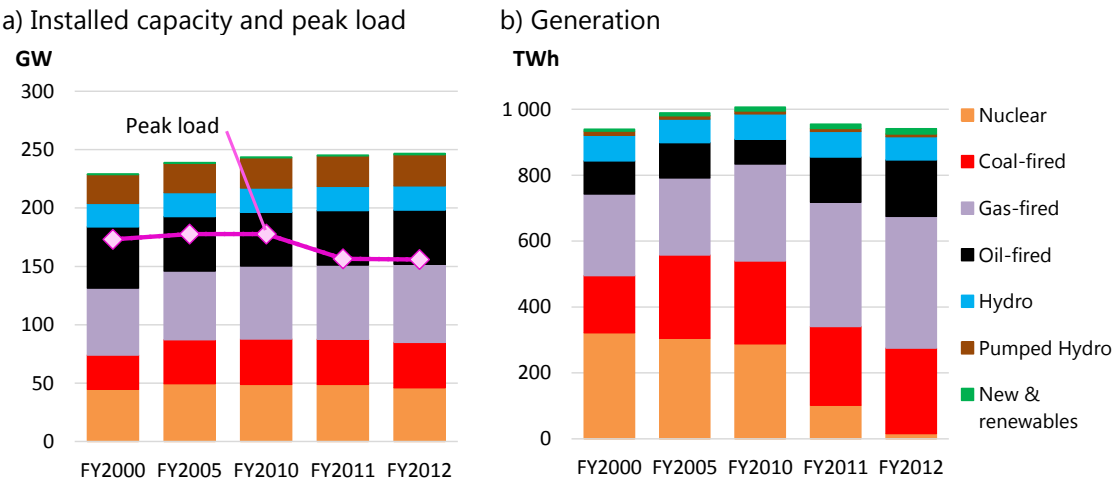
2.2.2. ELECTRICITY DEMAND AND SUPPLY

Especially after the two oil crises, Japan has been trying to balance the '3E' (economy, energy and environment) factors and diversify the fuel mix of its power generation as shown in Figure 11. In FY2012, on a capacity basis, coal-fired plants accounted for 16%, gas-fired plants accounted for 27%, oil-fired plants accounted for 19% and hydro (including pumped hydro storage) plants account for 19% of power-generation capacity. Although there are uncertainties regarding future nuclear power utilisation, its share of total capacity has held steady at approximately 10%. The power-generation mix before FY2010, shown in Figure 11b), illustrates Japan's '3E' energy strategy. After the nuclear accident, nuclear power generation significantly decreased from 288TWh (29% of total generation) in FY2010 to 102TWh (11% of total generation) in FY2011 and further to 16TWh (2% of total generation) in FY2012. Fossil fuel-fired power plants, mainly gas-fired and oil-fired plants, replaced the losses of nuclear generation capacity; that is, in FY2011, gas-fired and coal-fired power generation increased by 83TWh and 62TWh, respectively, from the previous year.

[3] The scope of liberalization differs in Okinawa (FEPC, 2014a).
[4] The role of ESCJ was transferred to OCCTO, and ESCJ was dissolved on 31st March 2015.

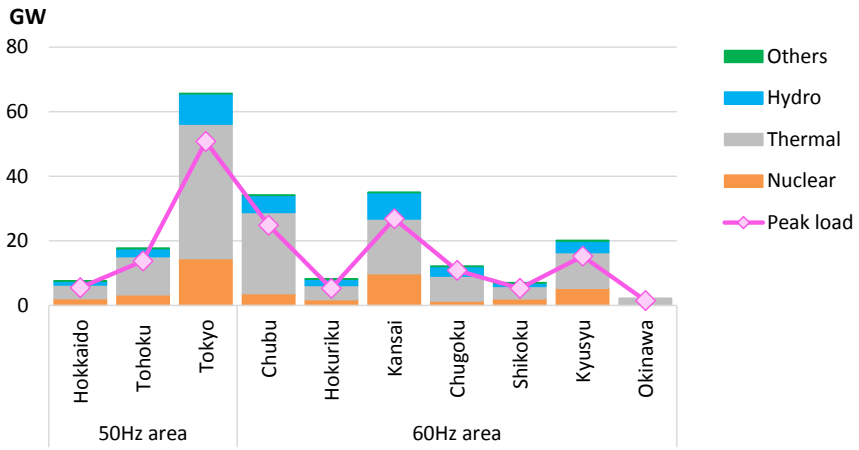
New and renewable (except hydro) energy sources gradually increased; however, its share in the total power-generation mix was 1.6% in 2012. Peak load usually occurred in the summer season in Japan, and it showed a slight growth for 2000–2010 at a 0.5% AAGR. After the nuclear accident, strong energy saving efforts in the economy contributed to a peak load reduction of 22GW in FY2012 from FY2010.

Figure 11 Historical power-generation capacity, peak load and generation, Japan



Sources: METI (2014b) and EDMC (2015).
Note: Figure 11 shows capacity and generation data of 10 general electric power utilities.

Figure 12 Installed power-generation capacity and peak load level by power utilities, Japan, FY2012



Source: EDMC (2014).

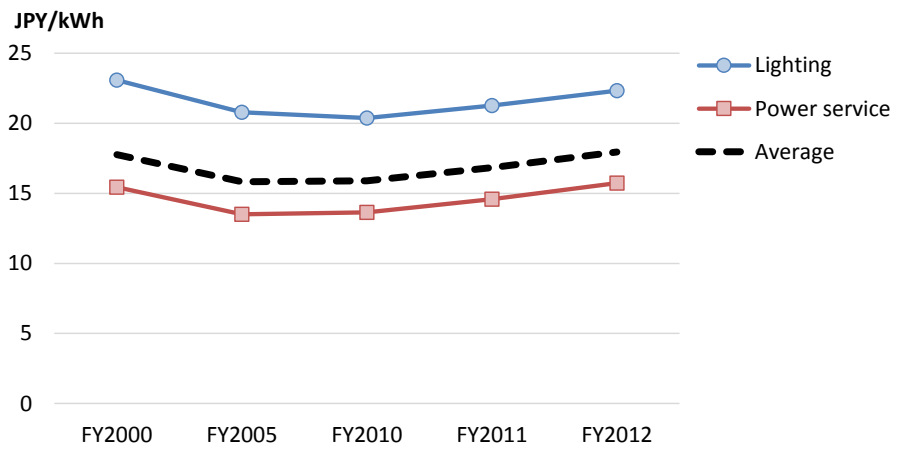
The largest power grid is the Tokyo electric power company area (Figure 12). Installed capacity owned by Tokyo Electric Power Company accounts for 30% of total ten electric power utilities (as of FY2012). The 50Hz area comprises three electric power

companies. Hokkaido is connected to the Tohoku area (Honshu island) via the Kitahon high voltage direct current (HVDC) link (250kV, 600MW), and another 300MW link is planned to be installed by 2019. The 60Hz area comprises seven electric service areas. Kyusyu island and Shikoku island are connected to Honshu island via Kanmon Interconnecting Line (500kV, 5570MW) and Honshi Interconnecting Line (500kV, 2400MW), respectively. In addition to three existing frequency conversion stations (total 1200MW) between 50Hz and 60Hz areas, Tokyo Electric Power Company and Chubu Electric Power Company plan to install a DC link with a capacity of 900MW in about FY2020 (OCCTO, 2015).

According to RITE (2014), the average efficiency of a Japanese thermal power plant between 2009 and 2011 was 44.7% (at the generation end, on an LHV basis), higher than the global average by 7.4 points. During the same period, the average efficiency of coal-fired plants was 41.4%, and of gas-fired plants was 47.9%. Coal-fired power plants in Japan maintained the highest efficiency in the world as of 2011.

Figure 13 describes historical electricity prices in Japan. As of 2015, Japan's electricity market is partially liberalised[5], and the electricity price for non-liberalised markets (low voltage, less than 50kW) is regulated by the Ministry of Economy, Trade and Industry (METI). Electric power utilities have to obtain permission from a METI minister to increase the regulated electricity prices. Japan's electricity prices have been one of the highest among developed economies.

Figure 13 Historical electricity prices, Japan



Source: METI (2014b).

Average prices were 22.3 JPY/kWh for lighting and 15.7 JPY/kWh for power services. The prices show decreasing trends from 2000 to 2010, partly because of the efficient

[5] Electricity market is planned to be fully liberalised from April 2015. See Section 2.2.3.

operation efforts (Kyuden, 2015). However, after the accident, many utilities applied to increase regulated electricity prices due to the increasing fuel costs for thermal power plants. According to NHK (2014), electric power utilities have increased electricity prices by 13%–37% from March 2011 to July 2014.

2.2.3. ECONOMY'S ENERGY PLAN

In April 2014, the Cabinet decided to approve the revised Strategic Energy Plan. This fourth plan gives a direction to Japan's energy policies for the medium/long-term (approximately the next 20 years). The revised plan states that the period from now to 2018-2020 is devoted to building more liberalised and competitive energy markets (METI, 2014c). In addition to electricity market reform mentioned in Section 2.2.1, amendments to the Gas Business Act were enacted in June 2015 to fully liberalise the gas retail market by about 2017 and to legally unbundle gas pipes owned by three town gas utilities, Tokyo Gas, Osaka Gas and Toho Gas, by April 2022 (METI, 2015a).

Under the Strategic Energy Plan, Japan will decrease nuclear dependence while strengthening energy efficiency and expanding renewable energy use. Accordingly, in July 2015, the expert committee in METI concluded Japan's Long-term Energy Supply and Demand Outlook. The committee projected energy demand to 2030 using macroeconomic indicators, and calculated total energy savings with a bottom-up estimation about sectorial savings potential. The Outlook indicates an electricity mix, primary energy demand and supply, and energy-related CO_2 emissions (Koyama, 2015), and aims to ensure the 'S+3E' policy where 'Safety' is the foremost condition. It has three steps: 1) increase energy self-sufficiency (including nuclear as quasi-domestic energy) to 24.3% from 6% in 2012; 2) lower electricity costs by 2% to 5% from FY 2013 levels; and 3) reduce energy-related CO_2 emissions by 21.9% from FY 2013 levels, to bring total GHG reductions to 26% (METI, 2015b).

The long-term outlook aims for a well-balanced generation mix where nuclear accounts for 20-22% of total generated electricity, renewables for 22-24%, liquefied natural gas for 27%, coal for 26% and oil for 3%. The share of nuclear is smaller than before the earthquake (when it was about 30%), thus lowering nuclear dependence. Within renewables, the two largest sources are hydro, accounting for 8.8-9.2%, and solar (7.0%). However, the outlook assumes radical energy savings: energy intensity in TFEC needs to be improves by 35% from 2012, equivalent to the drastic improvements after the oil crises. Therefore, economy-wide efforts --especially in commercial and residential sectors-- would be necessary to realise the outlook. It is also important to note that Projected demand assumes a 1.7% economic growth rate based on the 'revitalized economy' policy (CAO, 2015), which assumes higher growth than recent actual growth.

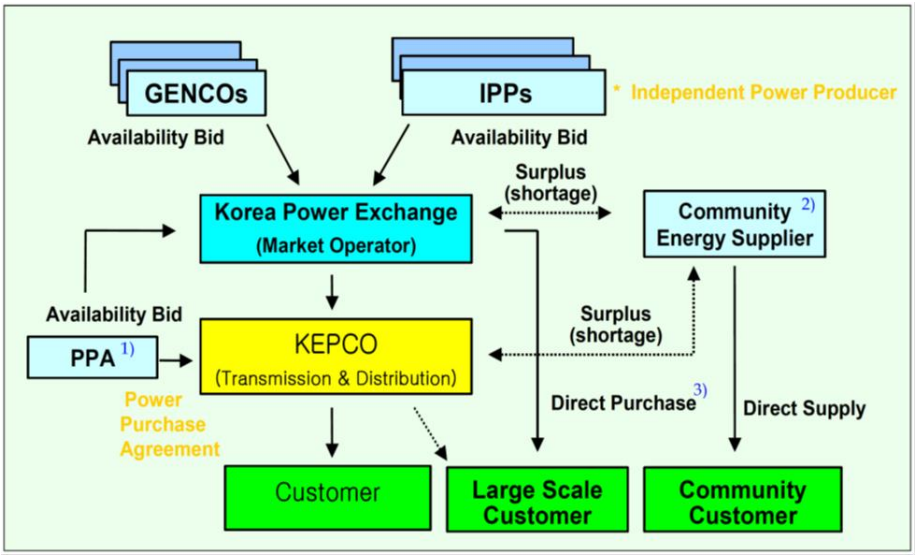
2.3. KOREA

2.3.1. ELECTRICITY MARKET AND POWER GRID

Korea's electricity industry is dominated by Korea Electric Power Corporation (KEPCO). Its generation section was separated into six power-generation companies in April 2001. These are Korea Hydro & Nuclear Power, which owns the economy's nuclear-energy power plants and hydro power plants, and five generation companies, which took over ownership of thermal power plants and pumped hydro storage facilities. KEPCO retained the economy-wide transmission and distribution grids as shown in Figure 14. KEPCO purchases electricity from power markets (KPX: Korea Power Exchange) and delivers it to general consumers. Large-scale consumers (consuming more than 30,000kW) can directly purchase from KPX, and CES (Community Energy Suppliers) can directly supply energy to their licensed area. Figure 15 shows Korea's electric power grid (KEPCO, 2013). Its frequency is 60Hz, and the backbone transmission network has voltages of 345kV and 765kV.

To rectify an energy demand–supply structure that is overly dependent on oil, the construction of oil-fired power plants was strictly controlled, whereas the development of nuclear, coal and natural gas electricity-generation units was promoted. During the period of the Seventh Basic Plan (2015-2029), 13 nuclear-energy power plants (total 18.2GW), 20 coal-fired power plants (18.1GW) and 14 gas-fired power plants (10.1GW) were planned for construction (see also Section 2.3.3).

Figure 14 Electricity market, Korea



Source: KEPCO (2009).
Note: IPP = independent power producer; PPA = power purchase agreement; GENCO = generation company

Figure 15 Electric power grids, Korea

Source: KEPCO (2013).
Note: DC = Direct Current.

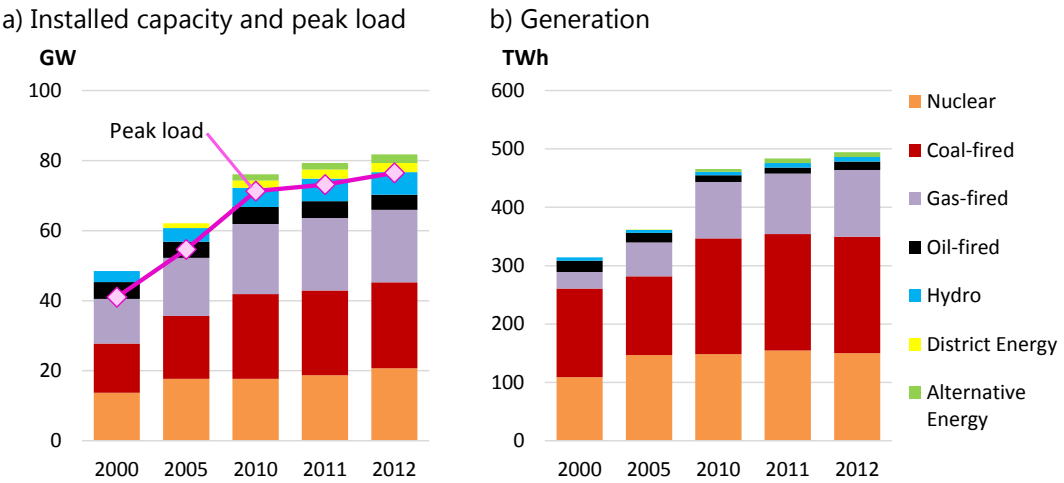
2.3.2. ELECTRICITY DEMAND AND SUPPLY

The power-generation capacity mix in Korea is dominated by thermal power generation (61%), mostly those based on coal and combined-cycle technologies. Nuclear power also has a significant share, accounting for approximately a quarter of

the installed capacity in 2012. The rest of the total power capacity consists of Hydro (8%), district energy (3%) and renewables (3%). The trend from 2000 to 2012 shows that thermal power generation has continued to grow from approximately 32GW in 2000 to 50GW in 2012. The capacity for district and renewable energy has also gradually increased since 2005. Peak load shows constant growth at a 5% AAGR. Peak load occurred in summer season before 2008. However, after 2009, the peak season has shifted to winter. Due to low-price electricity, most consumers in Korea use air conditioners for heating, resulting in larger electricity demand in winter (FEPC, 2013)

Korea's electricity generation increased from 118TWh in 1990 by over four times to reach 494TWh in 2012. The AAGR was highest during the first 10 years (1990–2000) at 9.4%, while in the latter 12 years, the rate is lower at an annual average of 3.8%. Most generation came from thermal power (66%), followed by nuclear power (30%). Thermal power generation was fuelled by coal (40% of total generation), gas (23%) and oil (3%) as described in Figure 16b).

Figure 16 Historical power-generation capacity, peak load and generation, Korea



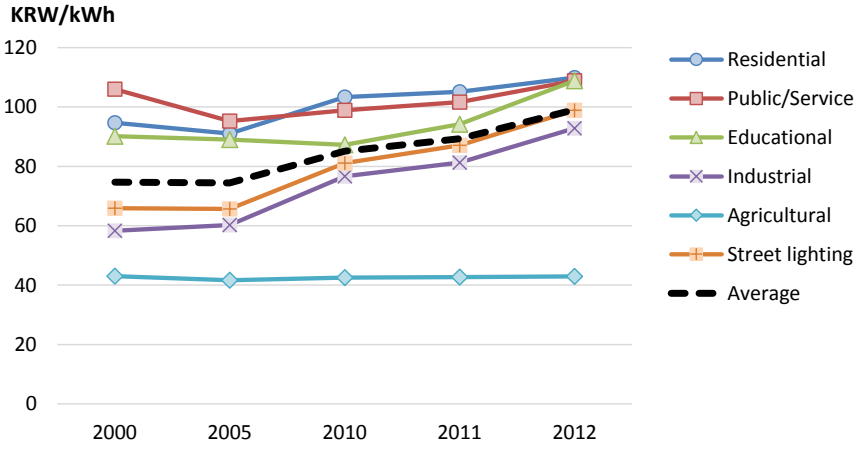
Source: MOTIE (2013).

According to RITE (2014), average efficiency of Korea's thermal power plants between 2009 and 2011 was 40.6% (at the generation end, on an LHV basis), higher than the global average by 3.3 points. The average efficiency of coal-fired plants for the three years was 36.1% and that for gas-fired plants was 51.0%. High-efficiency gas combined cycle is a dominant gas-fired plant type in Korea, and this technology contributes to improved efficiency.

Electricity tariffs in Korea are regulated by the government. Average revenue per kilowatt-hour sold in 2012 was 99.1 KRW. Prices, except for agricultural use, show an increasing trend from 2010 to 2012, as can be seen in Figure 17, due to increasing fuel prices and investment costs. However, regulated electricity prices are still lower

than the overall power-generation costs, and KEPCO has remained in a chronic state of deficit since 2008.

Figure 17 Historical electricity prices, Korea



Source: KESIS (2015).

2.3.3. ECONOMY'S ENERGY PLAN

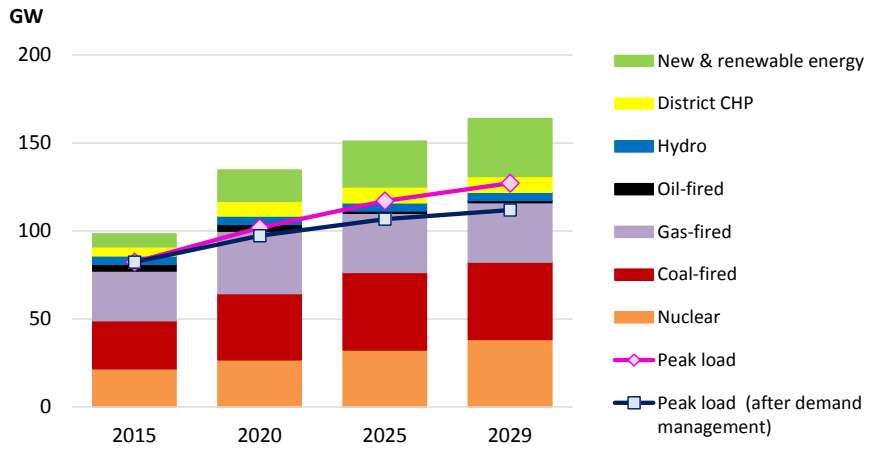
The 7th Basic Plan for Long-Term Electricity Supply and Demand was decided by MOTIE (Ministry of Trade, Industry and Energy) in July 2015. This is the Korean government's official electricity-sector plan. The 7th plan provides a forecast and plan for future electricity demand and supply up to 2029. General directions and highlights of the new plan are: 1) prioritisation of secure and stable electricity supply, 2) acceleration of low-carbon generation to reduce GHG emissions after 2020, 3) the first nuclear retirement in Korea (Kori-I in June 2017) and additions of two reactors, 4) cancellation of four new coal-fired plants, and 5) promotion of distributed renewables (MOTIE, 2015; JAIF, 2015).

The 7th plan foresees that Korea's electricity market steadily grows in terms of consumption, from approximately 498TWh in 2015 to 766TWh in 2029. Compared to the 6th plan, the growth slightly declines mainly due to the downward revision of GDP forecast. Annual peak load continues to occur in winter season (usually around December ~ January); however, summer peak (usually around August) remains the similar level to winter peak. Therefore, tight demand-supply situation is expected to occur both in summer and winter periods.

The 7th plan illustrates that approximately 14% of total demand (110TWh) is reduced by demand management measures, including the use of smart-metre, electricity pricing mechanisms, promotion of higher-efficient products, and so on (Figure 18). Coal-fired generation decreases its share; however, it still remains as the main fuel source due to growing demand. Despite the cancellation of four plants, coal-fired capacity is projected to increase from 27GW in 2015 to 44GW by 2029, respectively accounting for 28% and 27% in capacity mix. NRE (new and renewable) technologies

show the largest expansion among the fuel type, in terms of capacity, from about 6GW in 2014 to 33GW by 2029.

Figure 18 Future capacity projections, 7th Basic Plan for Long-term Electricity Supply and Demand



Source: MOTIE (2015).

2.4. RUSSIA

2.4.1. ELECTRICITY MARKET AND POWER GRID

Russia classifies its territory into seven integrated power systems (IPSs): IPS-Northwest, IPS-Center, IPS-Middle Volga, IPS-Urals, IPS-South, IPS-Siberia and IPS-East (Figure 19), and these IPSs comprise 69 regional power systems with a frequency of 50Hz (EBRD, 2010). Figure 20 describes Russia's transmission network area (Popel, 2012). Major existing cross-border interconnections from IPS-Siberia and IPS-East to neighbouring NEA economies (China and Mongolia) are given in Table 1.

Russia began restructuring its power industry in 2000. All thermal-generation and regional power-distribution companies were privatised before July 2008. From July 2008, the generation and transmission assets in Russia have been separated under binding regulations. Generation assets are consolidated into two types of interregional companies: 7 wholesale generation companies (WGCs) and 14 territorial generation companies. Six WCGs were established, with one state-owned holding company (RusHydro) which controls over 53 hydro power plants. Each WGC has power plants sited in different regions to prevent the emergence of a possible electricity market monopoly.

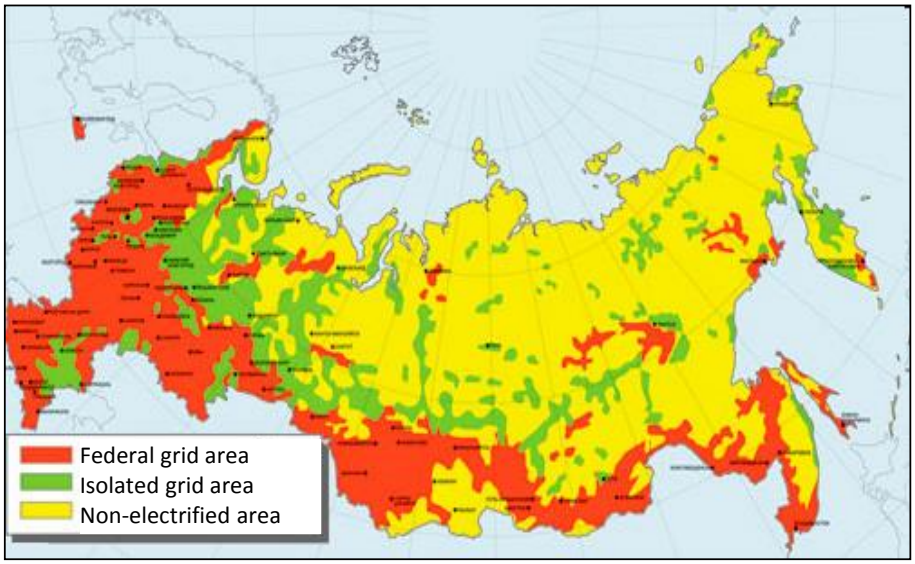
Ultra-high-voltage (UHV) and high-voltage (HV) transmission lines are mainly assigned to the Federal Grid Company of Unified Energy System (FGC UES), whereas middle- and lower-voltage lines and distribution grids are owned and operated by inter-regional distribution grid companies. FGC UES is the operator and manager of

Russia's unified electricity transmission grid system, including HV transmission lines, and holds the status of a natural monopoly (FGC UES, 2014). The Federal Antimonopoly Service is in charge of monitoring the long-distance power-transmission market.

Figure 19 Power grids, Russia

Source: EBRD (2010).
Note: IPS=integrated power system.

Figure 20 Transmission network areas, Russia



Source: Popel (2012).

The free electricity trading market (one-day forward) was launched in November 2003 within the framework of the Federal Wholesale Electricity Market (FOREM). In

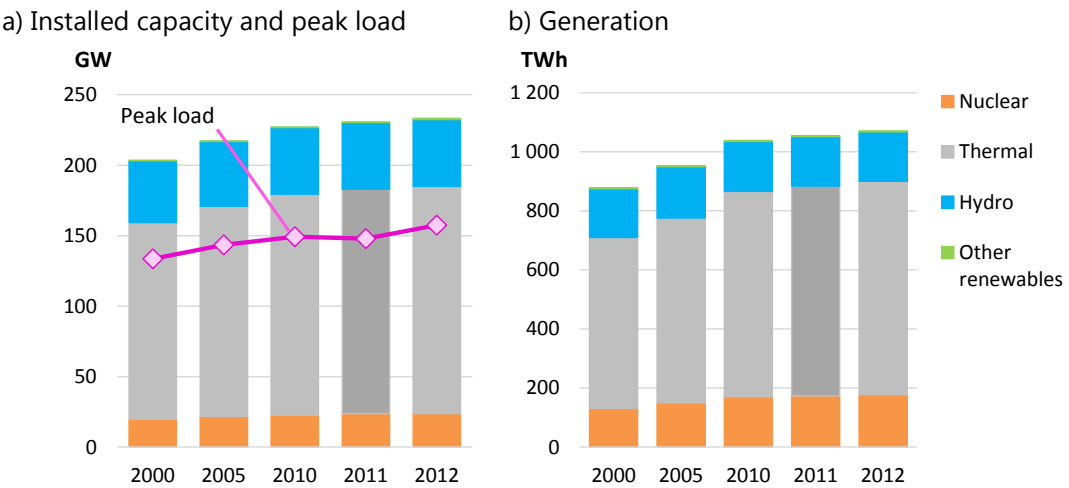
September 2006, the regulated sector of the wholesale market was replaced by a system of contracts to be concluded between buyers and sellers.

As mentioned below, Russia is interconnected to various regions, including China, Kazakhstan, Georgia, Mongolia, South Ossetia, Ukraine and Azerbaijan. Inter RAO, a public[6] Russian company, manages cross-border electricity trading.

2.4.2. ELECTRICITY DEMAND AND SUPPLY

Russia's power-generation capacity reached approximately 233GW in 2012 (Figure 21) at an AAGR of 1.1% from 2000. Thermal power plant capacity holds the biggest share, at approximately 69% over the last decade. The peak load season is winter. Russia has developed the largest and oldest district heating (DH) systems in the world, and has almost 500 combined heat and power stations, 200,000km of DH pipeline network, and more than 65,000 boiler houses (IEA, 2009).

Figure 21 Historical power-generation capacity, peak load and generation, Russia



Sources: EIA (2015), JEPIC (2014a).

Concerning the power-generation mix in 2012, thermal power plants account for 67%, hydro power plants for 16% and nuclear for 17%. Nuclear generation increased by 1.35 times between 2000 and 2012, whereas hydro power plants remained at the same level (1.01 times). Renewables (except hydro) increased by 35% from 2000; however, its share has remained at approximately 0.3% over the last decade.

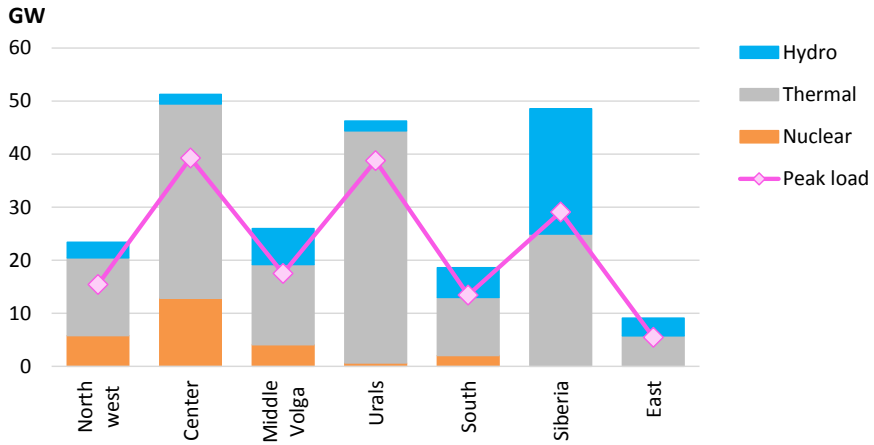
In 2012, the volume of exports amounted to 18.4TWh, which is 4.3TWh less than in 2011 (–19.1 %). The decline in exports is due to lower purchase volumes by the

[6] State-owned entities are the major shareholders of Inter RAO.

Republic of Finland (–60.6% compared to 2011). The main directions of exports in 2012 were Lithuania (26.0 % of total exports), Finland (20.7 % of total exports) and Belarus (20.1% of total exports). Electricity was also supplied to China (14.3% of total exports), Kazakhstan (12.4% of total exports), Georgia, Mongolia, South Ossetia, Ukraine and Azerbaijan. In 2012, electricity imports totalled 2.6TWh, which is 0.8TWh less than in 2011 (–23.8 %). The decline was recorded in all electricity imports. The main origins of electricity imports in 2012, as well as in 2011, were Kazakhstan (75.7 % of total imports) and Georgia (14.1% of total imports). Russia also imports from Azerbaijan, Mongolia and Belarus.

The scale of Russia's power grids varies from region to region (Figure 22). As mentioned in Section 4, our study's definition includes a part of IPS-Siberia and IPS-East as city nodes. IPS-East has the smallest grid scale in terms of installed capacity, mainly comprising 5.7GW thermal power plants and 3.3GW hydro power plants. The total installed capacity in IPS-Siberia is the second largest among the seven power systems, mostly comprising hydro power plants (23GW in 2012).

Figure 22 Installed capacity and peak load by power grid, Russia, 2012



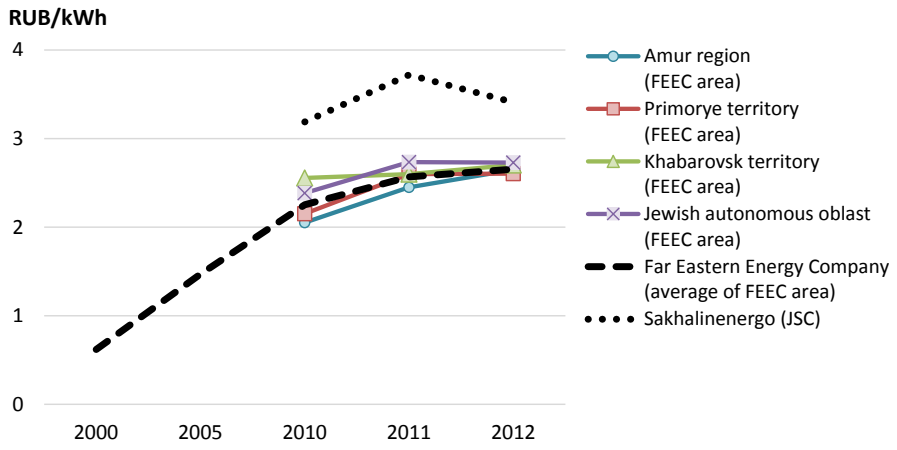
Source: JAIF (2013).

According to RITE (2014), the average efficiency of Russian thermal power plants between 2009 and 2011 was 31.8% (at the generation end, on an LHV basis), which is lower than the global average by 5.5 points. The average efficiency of coal-fired and gas-fired plants for the three years was 30.6% and 32.3%, respectively. RITE (2014) reported that over the last ten years, both coal-fired and gas-fired plant efficiency in Russia has remained constant.

Figure 23 indicates historical average electricity prices in Russia in the areas for both the joint stock companies 'Far Eastern Energy Company (FEEC)' and 'Sakhalinenergo'[7]. Electricity in isolated power grids in the Far East region is sold through regulated retail markets at regulated prices. For the Amur Region, Khabarovsk and Primorye territories as well as the Jewish Autonomous region, the electricity tariff for end consumers in the retail market is determined based on the principles of wholesale prices translation provided in the 'Fundamental Principles and the Rules for Applying Prices/Tariffs' approved by the Order of the Russian Federal Tariff Service dated 30 November 2010, No. 364-e/4.

The electricity prices in the Far East area show increasing trends over the last decade. The average value in the FEEC area rose by 4.3 times from 2000 to 2012 (from 0.62 RUB/kWh to 2.65 RUB/kWh) at an AAGR of 13%. Electricity prices in the Sakhalin area are higher than those in the FEEC area by approximately 30%.

Figure 23 Historical average electricity prices, Russia's Far East region (Far Eastern Energy Company area and Sakhalinenergo area)



Source: RAO Energy System of East (2013).
Note: FEEC = Far Eastern Energy Company. The value of 'FEEC average' in 2005 and 2000 is derived from the average tariff for the whole Far East electricity system.

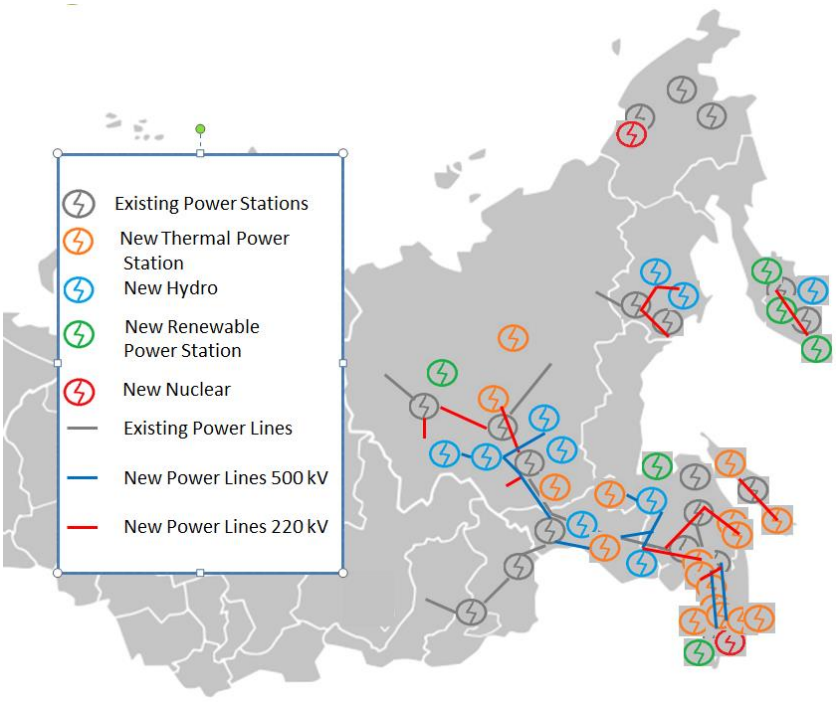
2.4.3. REGIONAL ENERGY PLAN

Figure 24 shows the power development plan till 2030 in Russia's Far East region. The installation of a 500kV transmission line is planned for the Far East's power system to strengthen its backbone transmission networks. In addition, the plan mentions a 200kV-scale new power line in Sakhalin. The region has nuclear development plans with a total capacity of 1120MW until 2030, hydro power development plants (total

[7] These areas belong to IPS-East in Figure 19.

capacity: 1680MW), new and renewable energy (total capacity: 400MW) and thermal power plants (total capacity: 9400MW).

Figure 24 Russia's Far East power sector development, up to 2030.



Source: Saneev & Sokolov (2015).

2.5. COMPARISON OF THE MAJOR INDICATORS ACROSS NEA REGION

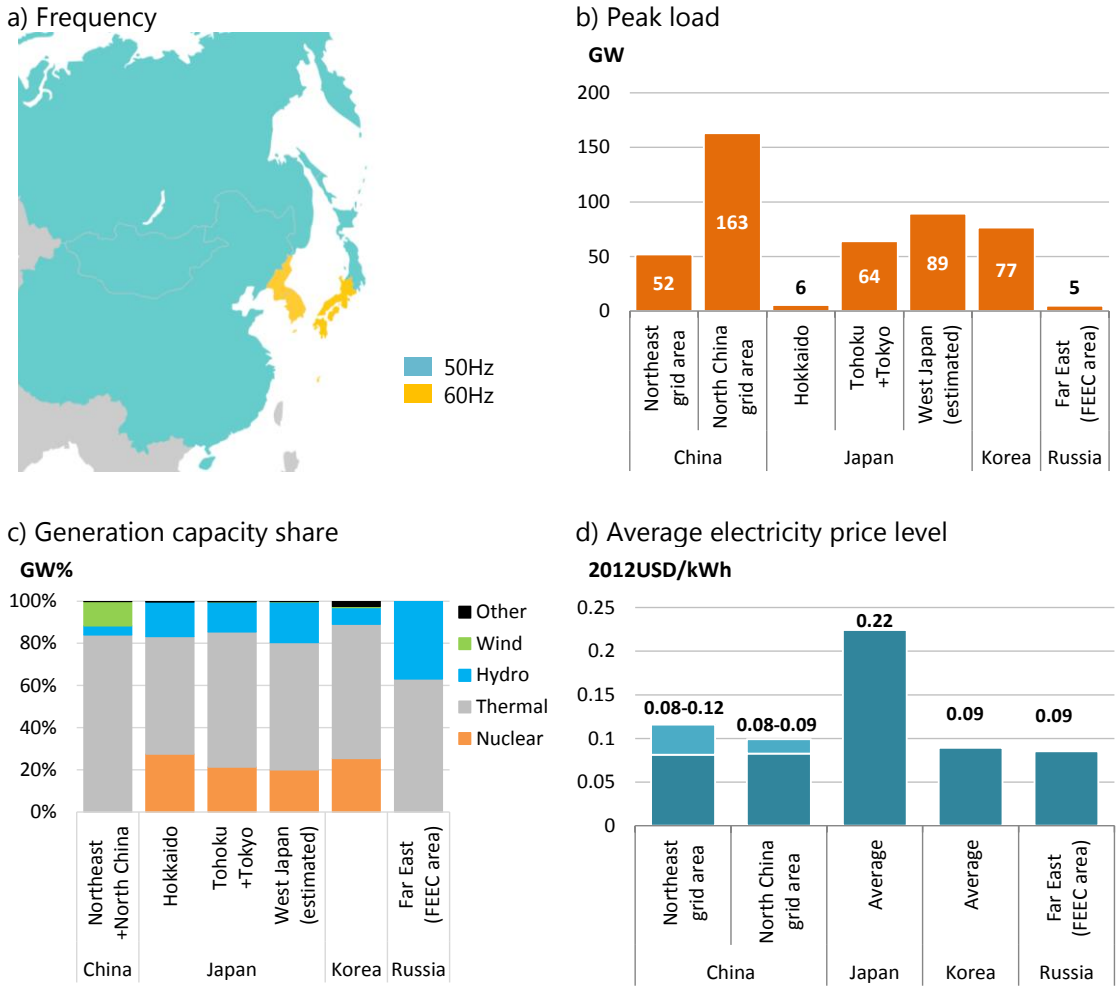
Section 2 summarised the electricity market, electricity demand and supply situation, and regional energy plans in NEA. This section compares the major indicators in the NEA's different sub-regions. Figure 25 shows the frequency, peak load, power generation mix, and electricity prices.

Figure 25a) describes the frequency in this region, including in Mongolia and DPRK. The NEA region comprises a 50Hz area (China, the east part of Japan, Mongolia and Russia) and a 60Hz area (the DPRK, the western parts of Japan, and Korea). As Section 3.2 subsequently mentions, the Russia (50Hz) and Korea (60Hz) are interested in connecting their regions, and the Korean utility has displayed an interest in China (50Hz)–Korea (60Hz) interconnections. These cases propose HVDC interconnections, which are feasible from a technical viewpoint.

Figure 25b) indicates the peak load in each sub-region. Japan is disaggregated into three categories in the figure: the Hokkaido island area (50Hz), Tohoku+Tokyo area (50Hz) and the rest of Japan ('west Japan', 60Hz), which correspond to the modelled

nodes in Section 4. The North China power grid, which includes the Beijing area, is the largest among the sub-regions. Its scale (163GW) is approximately two–three times larger than the China Northeast, Tohoku+Tokyo, west Japan or Korea grids. In contrast, the Hokkaido (Japan) and Far East (Russia) areas are relatively small (approximately 5GW).

Figure 25 Comparison of major indicators, Northeast Asia region, 2012



Note: FEEC = Far Eastern Energy Company. Figure 25a) shows frequency in Mongolia and DPRK for reference. The peak load in west Japan in Figure 25b) is estimated from the monthly peak load data in each power service area. Figure 25d) shows average prices in 2012 for Japan, Korea and the Russia FEEC area. Average exchange rates in 2012 are assumed for this comparison. For the North China and Northeast China grids, the graph shows the ranges of electricity prices in each region.

Each region relies on thermal power plants (Figure 25c)). The nuclear capacity shares in Japan and Korea are more than 20%. Hydro capacity accounts for approximately 37% in Russia's Far East region and approximately 14%–20% in Japan's regions. In contrast, the hydro capacity share is relatively small in Korea (8%) and in Northeast+North China (4%). Overall, China has abundant hydro resources (economic potential: 402GW and 1750TWh/y). However, these resources are distributed mainly

in the western and southern parts of China, and the economic potential in the Northeast+North China area is only 5.4% (approximately 22GW) (Huang & Yan, 2009). Instead, wind resources are plentiful in northern parts of China, and this source's capacity in the Northeast+North China grid reached 41GW (12% in capacity mix) in 2012 (JEPIC, 2014a).

The average price in Japan (0.22 USD/kWh) is approximately double that of other regions (Figure 25d)). The prices in other regions (northeast part of China, Korea and Far East Russia) are at a similar level (approximately 0.09–0.12 USD/kWh). China and Russia have faced difficulties in agreeing on power imports/exports prices and their power trade was disrupted twice (Sakai, 2014). In general, a larger domestic price gap provides more appropriate conditions for power trades to ensure profit margins (between trading price and domestic price). Conversely, unless these average prices hide significant differences by period (season/time of day), it remains hard to secure certain margins from the power trade among the economies with similar electricity prices (for example, China, Korea and Russia in 2012).

3.MAJOR CONCEPTS OF POWER GRID INTERCONNECTIONS

This section summarises the major grid interconnection concepts in NEA. First, this section outlines NEA region-wide grid interconnection concepts (Section 3.1). Then, Section 3.2 focuses on the proposals of each individual (bilateral) interconnection.

3.1. NEA-WIDE GRID INTERCONNECTION CONCEPTS

Since the 1990s, grid interconnection concepts—for example, 'Northeast Asian Electrical System Ties' (NEARST)—have been discussed mainly by Melentiev Energy System Institute, Siberian Branch of the Russian Academy of Science (ESI SB RAS) with a focus on investment savings and power-system reliability improvements (KERI, 2003; EN+, 2012; Belyaev, et al., 2014). However, cross-border power grid connections have not been explored fully in NEA thus far, and discussions stagnated in the latter half of the 2000s. Around or after 2010, several regional events mentioned (Section 1) made interconnections more attractive as a means of promoting renewable energy, building a resilient power system and achieving an economical electricity supply (by levelling demand or effective use of fossil fuel resources). According to our survey, six out of seven major concepts has been proposed after 2010 (Table 3).

The mainly focused energy sources in 'Asia Super Grid' (JREF, 2011), 'Asia Pacific Power Grid' (Japan Policy Council, 2011) and 'Gobitec and Asian Super Grid' (Energy Charter, et al., 2014) are renewable energy; in particular, these concepts emphasise that larger grid scale due to interconnections contributes to integrating variable renewables. Other concepts include effective utilization of fossil fuel-fired plants as well. 'GRENATEC' (GRENATEC, 2010) proposes a shift from carbon-intensive coal to cleaner fuel, including renewables and natural gas, by enhancing power grid and gas pipeline connectivity. 'Northeast Asia Super Grid' (Skoltech, 2014a) focuses on thermal plants and conventional renewables. Massive deployments of variable renewables are not considered in this concept. Geographical coverage varies concept by concept. Three of the concepts (GRENATEC, Asia Super Grid and Asia Pacific Power Grid) propose connecting power grid to outside NEA regions, such as ASEAN and Australia grid.

Various interconnection concepts have been proposed by various private companies or research institutes; however, there is limited coordination by economy's authorities or international/regional organisations (like HAPUA in the ASEAN region) so far. In order to draw up a detailed blueprint as well as to research, discuss and implement the concepts in an effective manner, a coordinating entity should be established.

Table 3 Major region-wide grid interconnection proposals, Northeast Asia

Proposal title (Source)	Main related organisations	Quick descriptions
NEAREST (Northeast Asian Electrical System Ties) (Belyaev, et al., 1998; KERI, 2003; EN+, 2012)	• Melentiev Energy System Institute, Siberian Branch of the Russian Academy of Science • Korea Electrotechnology Research Institute	• **Geographical scope**: China, Japan, Korea, Mongolia and Russia. • **Purpose**: peak-load sharing, investment or operation costs reduction and reliability enhancement • Several quantitative analyses on the certain connection routes have already been conducted.
GRENATEC (GRENATEC, 2010)	• GRENATEC	• **Geographical scope**: ASEAN nations, Australia, China, Japan, Korea and Chinese Taipei. • **Purpose**: shift from coal-fired to gas-fired and renewable energy • Proposed connections include power lines as well as gas pipelines and fibre optic cables to realise 'cloud energy'.
Asia Super Grid (JREF, 2011)	• Japan Renewable Energy Foundation	• **Geographical scope**: Bangladesh, Bhutan, China, India, Japan, Korea, Malaysia, Philippines, Singapore, Chinese Taipei, Thailand and Russia • **Purpose**: demand levelling, resilience enhancements, renewable energy promotion and fair electricity price
Asia Pacific Power Grid (Japan Policy Council, 2011)	• Japan Policy Council	• **Geographical scope**: ASEAN power grid region, Australia, Japan, Korea and Chinese Taipei. • **Purpose**: renewable energy promotion • Propose establishing 'Green Energy Grid Organization' (tentative name) to realise an Asia Pacific Power Grid.
NEA Super Grid (KEPCO, 2014a)	• Korea Electric Power Corporation	• **Geographical scope**: China, Japan, Korea, Mongolia and Russia • **Purpose**: energy resource sharing, demand levelling and power system reliability improvements

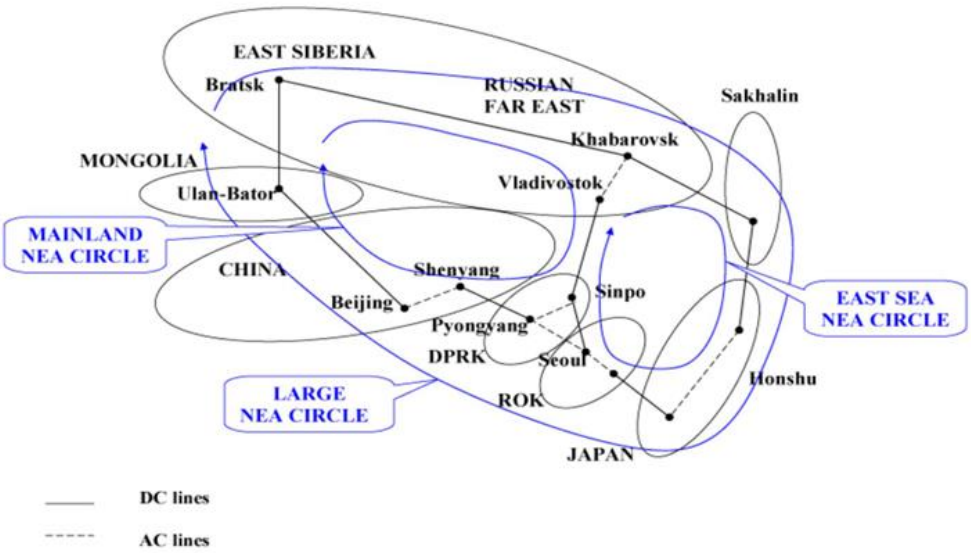
Proposal title (Source)	Main related organisations	Quick descriptions
Gobitec and Asian Super Grid (Energy Charter, et al., 2014)	• Energy Charter Secretariat • Korea Energy Economics Institute • Energy Systems Institute, Russian Academy of Science (ESI RAS) • Ministry of Energy, Mongolia • Japan Renewable Energy Foundation	• **Geographical scope**: China, Japan, Korea, Mongolia and Russia. • **Purpose**: renewable energy promotion. • Massive integration of wind (50GW) and solar (50GW) power generation in the Gobi desert area • HVDC connection from Gobi desert area to other related regions • Electricity supply costs [USD/kilowatt-hour] estimated from the Gobi area
Northeast Asia Super grid (Skoltech, 2014a)	• Skolkovo Institute of Science and Technology (Skoltech) • Melentiev Energy Systems Institute, Siberian Branch of the Russian Academy of Science • En+ Group • Korea Electric Power Corporation • Korea Energy Economics Institute	• **Geographical scope**: China, Japan, Korea, Mongolia and Russia. • **Purpose**: energy resource sharing, demand levelling • Three interconnection options from Russia to Korea • Modelling and analysis work finished in April 2015.

Note: ASEAN = Association of Southeast Asian Nations; HVDC = high-voltage direct current.

3.1.1. NORTHEAST ASIAN ELECTRICAL SYSTEM TIES (NEAREST)

The NEAREST concept has been discussed since the 1990s, led mainly by Melentiev Energy Systems Institute, Siberian Branch of the Russian Academy of Science (ESI SB RAS). NEAREST's proposed geographical scope covers China, Japan, Korea, Mongolia and Russia (Figure 26). Belyaev et al. (2014) summarised the potential benefits of NEAREST as follows: a) decreasing demand for installed generation capacities due to diversity in daily and yearly peak loads, b) increasing reliability of electric power systems to be interconnected, c) involvement of large renewable energy (primarily hydropower) sources in the energy balances of different countries, d) acquisition of incomes from electricity trade and e) reduction of electricity prices.

Figure 26 Northeast Asian Electrical System Ties concept



Source: Belyaev, et al. (1998).
Note: NEA = Northeast Asia; AC = alternating current; DC = direct current.

Chung and Kim (2007) analysed the economic feasibility of the NEAREST concept with a focus on DPRK, Korea and Russia. They employed a mathematical optimisation (linear programming) model, called ORIRES, originally developed by ESI SB RAS. They conducted simulations under the assumption that imported electricity contributes to achieving the reserve margin criteria of the importing region (see Equation (2) in Chung and Kim (2007)), and concluded that power grid interconnection produces immense economic benefits due to avoiding the construction of new power plants (Table 4). Interconnections reduce the total annual system costs by 7%–11.1% each year.

Table 4 Independent system vs. interconnection system, economic evaluation

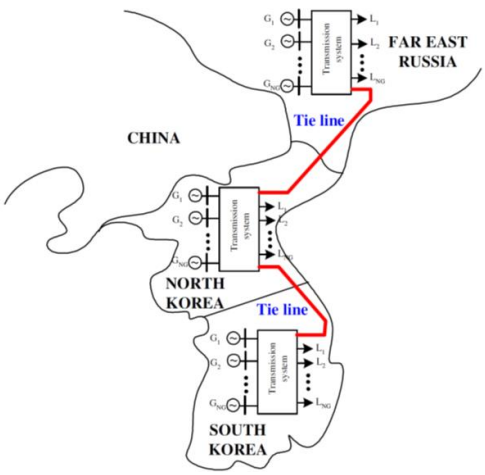
		Interconnected line investment cost	Generating facility investment cost	Fuel cost	Total
Year 2010	Independent	-	3 595	9 660	13 254
	Interconnected	168	2 052	10 103	12 323
	Total cost changes	-	-	-	-7.0%
Year 2015	Independent	-	7 268	9 785	17 053
	Interconnected	234	5 156	9 898	15 288
	Total cost changes	-	-	-	-10.4%
Year 2020	Independent	-	10 895		20 918
	Interconnected	298	7 462		18 591
	Total cost changes	-	-	-	-11.1%

Source: Chung & Kim (2007). APERC reproduces the table based on the information in the source.

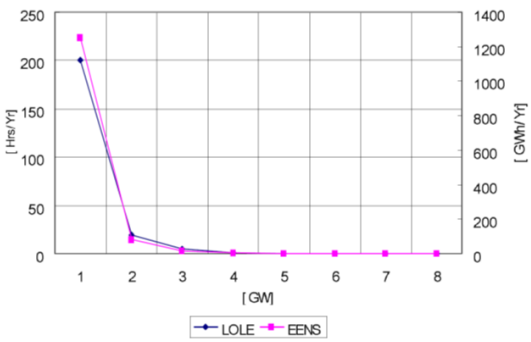
Choi et al. (2006) and Yoon (2007) analysed the benefits to power-system reliability from grid interconnections between Korea, DPRK and Russia's Far East region. These researches developed a reliability evaluation model, called NEAREL (NREAREST-Reliability), to assess reliability indices including loss of load expectation (LOLE) and expected energy not supplied (EENS) in the related economies. Choi et al. (2006) examined the reasonable interconnection capacity using sensitivity analysis, and Yoon (2007) analysed the reliability of four interconnection scenarios between Korea and Russia's Far East region. Figure 27a) shows the interconnection scenario examined in Choi et al. (2006), and Figure 27b) shows the simulation results in Korea (LOLE and EENS). Figure 27b) indicates that reliability indices show a saturation trend from approximately 3GW tie-line capacity.

Figure 27 Reliability assessment of NEAREST concept (example)

a) Schematic diagram of the study



b) Results of Korean power system reliability assessment



Source: Choi, et al. (2006).
Note: LOLE = loss of load expectation; EENS = expected energy not supplied.

3.1.2. GRENATEC

GRENATEC is a private research organisation studying the viability of a 'Pan-Asian Energy Infrastructure' (GRENATEC, 2010). The proposed concept would connect Australia to Northeast Asia via the South and East China Seas through a combination of HVDC transmission lines, gas pipelines and fibre optic infrastructures (Figure 28). The aim is to create flexible cross-border energy and information networks to replace carbon-intensive coal energy with gas and renewable energy in the region. The network is called 'cloud energy' in GRENATEC, and pipeline gas and renewable electricity are intended to be traded like network packets in the telecommunications field. They advocate realisation of this concept by 2050.

Figure 28 Pan-Asian Energy Infrastructure concept

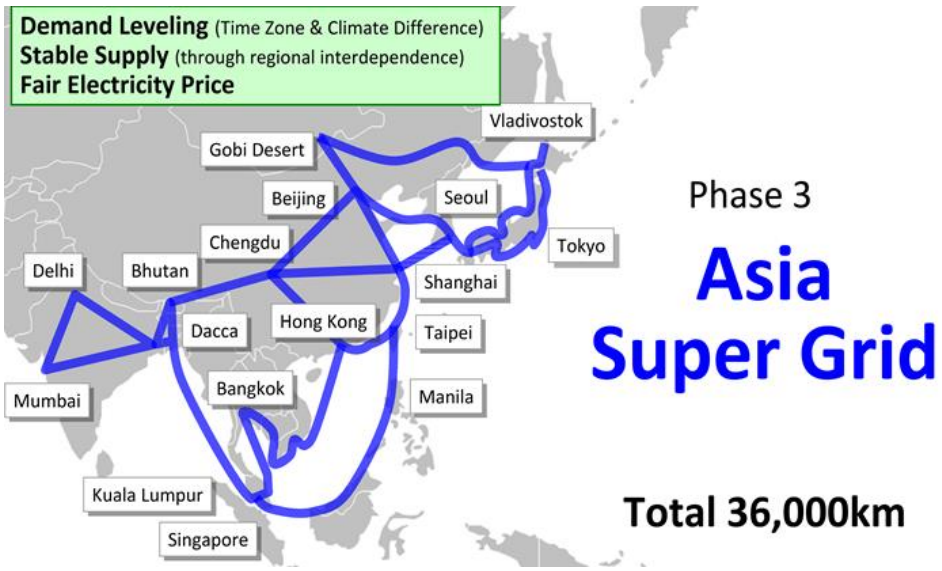
Source: GRENATEC (2010).

3.1.3. ASIA SUPER GRID

The Japan Renewable Energy Foundation (JREF) proposed the Asia Super Grid concept (Figure 29) in September 2011 (JREF, 2011). This concept entails connecting countries in the NEA region (such as Japan and Russia) and South Asia countries (such as India) through Southeast Asia via HVDC transmission line technology. The objectives of establishing these interconnections are demand levelling, stable electricity supply and fair electricity prices. Electricity prices in Japan are approximately 0.2 USD/kWh, which is twice to ten times as expensive as in other Asian counties. According to their concept, HVDC transmission losses are approximately 5% for 3,000km transmission length, and it could be cost effective for the region. They also insist that this super grid is an effective means for large-scale integration of renewable energy as time-zone and climate differences contribute to smoothing output variations. This concept does not include quantitative analyses of

costs and benefits. However, as mentioned in Section 3.1.5, JREF is actively pursuing this topic.

Figure 29 Asia Super Grid concept



Source: JREF (2011).

3.1.4. ASIA PACIFIC POWER GRID

Japan's Policy Council (Chair: Mr. Hiroya Masuda, Former Minister of Internal Affairs and Communications from August 2007 to September 2008) proposed the Asia Pacific Power Grid concept, which would connect Japan and Korea to Australia through Southeast Asian countries as depicted in Figure 30. This proposal was the Council's first recommendation, advocating that 'Japan should propose and lead the realisation of an Asia Pacific Power Grid as part of its diplomatic strategy to establish a society based on renewable energy' (Japan Policy Council, 2011). They proposed five points as follows:

- An international power grid should be established to promote renewable energy and overcome its instability. Through an Asia–Pacific partnership in energy coordination, a mutually complementary framework should be created.

- Japanese renewable energy technologies should be transferred to Asia to strengthen the power supply in the region and secure a back-up power supply for Japan while contributing to the reduction of carbon dioxide emissions.

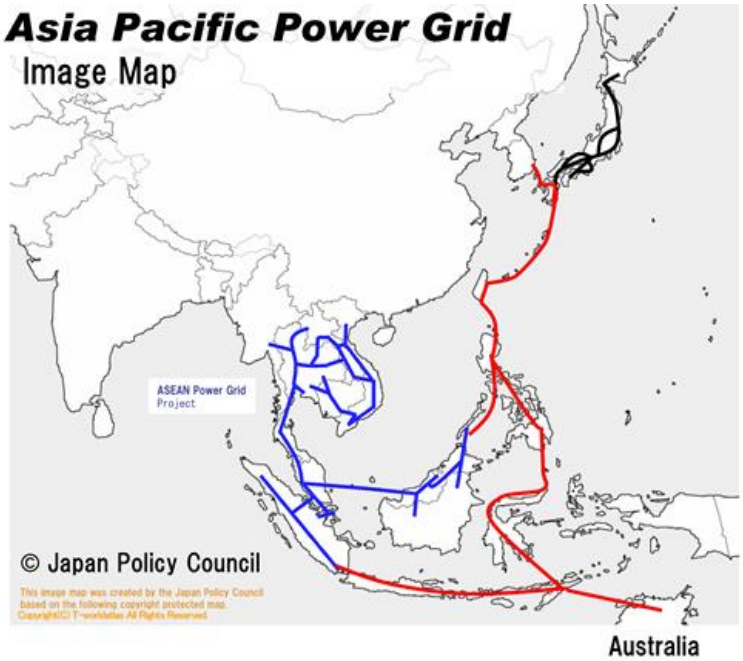
- An international platform, Green Energy Grid Organization (tentative name), should be created to promote renewable energy and establish the international power grid.

- To prepare for connections with the international power grid, a domestic power grid unifying the entire nation should be established, with separation between the generation and distribution of electricity.

- Research and development efforts that will lead to discontinuous innovations, such as lithium-air batteries, should be intensified.

Their proposal mainly concerns the concept's overall scope and does not include any quantitative analyses or assumptions about the economics involved.

Figure 30 Asia Pacific Power Grid concept



Source: Japan Policy Council (2011).

3.1.5. GOBITEC AND ASIAN SUPER GRID

The Gobitec and ASG initiatives conducted international research projects and published a report titled 'Gobitec and Asian Super Grid for Renewable Energies in Northeast Asia' in January 2014 (Energy Charter, 2014c). The initiative involves five project partners from related regions: Energy Charter Secretariat, Korea Energy Economics Institute (KEEI), ESI SB RAS, Ministry of Energy of Mongolia and JREF. Fraunhofer Institute for Systems and Innovation Research ISI and Fraunhofer Institute for Solar Energy Systems ISE joined as project consultants. JREF is actively researching this topic and organised an international symposium titled 'Roadmap to Asia Super Grid' in January 2014 (JREF, 2014).

The Gobitec concept represents the idea of producing clean energy from renewable energy sources in the Gobi desert and subsequently delivering the produced energy

to regions with high demand. The proposal calls for transmission of clean electricity via a large-scale cross-border transmission network—the ASG—which would connect Russia, Mongolia, China, Korea and Japan as shown in Figure 31. The overall potential of solar and wind energy in the Gobi desert is approximately 1.5TW and 1.1TW, respectively (Energy Charter et al. (2014), p.26). They propose the installation of 50GW solar power and 50GW wind power capacity. The total investment in construction and annual O&M costs are estimated to be approximately 294.6 billion USD and 7.4 billion USD/y, respectively (Table 5).

This initiative proposed the concept as well as conducted a first analysis of its technological, legal, economic and environmental opportunities/challenges. The key outcomes of their analysis are as follows:

- Technological: Due to the extensive electricity transmission distance, the study strongly recommended the use of point-to-point HVDC transmission lines. To maintain low transmission loss, the Gobitec network should be operated at a voltage of more than 1000kV.

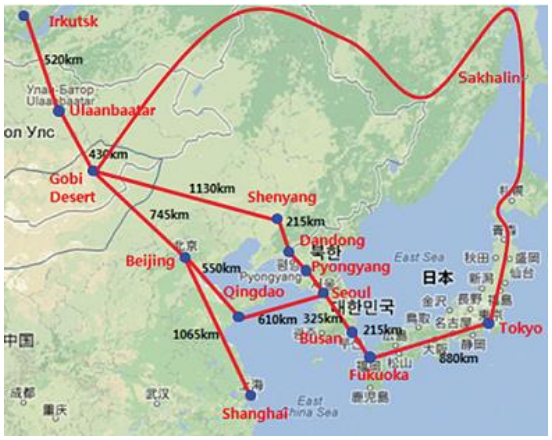
- Legal: The study concluded that a legal framework, the Energy Charter Treaty, is necessary for the enactment of the concept to ensure a positive investment climate, reliable transit regime and protection of property rights.

- Economic: The report estimated total supply unit cost (TSUC) [USD/kilowatt-hour] and weighted average electricity charge (WAEC) considering the distribution share of exported electricity (Table 6). By comparing TSUC and WAEC, the study concluded that the concept can be beneficial if the average capacity factor of the installed renewables is greater than at least 30%.

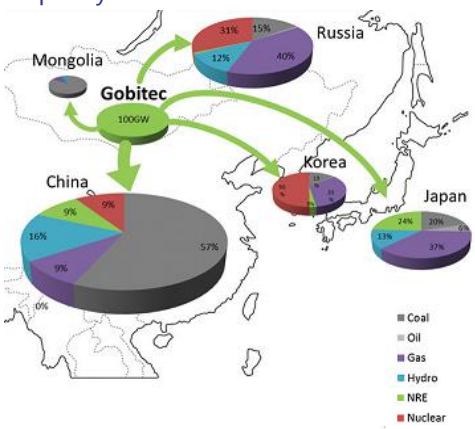
- Environmental: The study also estimated CO_2 reduction effects using emission factor data for 2011. Total CO_2 reduction of approximately 187Mt-CO_2 can be achieved: 149Mt-CO_2 in China, 21Mt-CO_2 in Korea, 13Mt-CO_2 in Japan and 4Mt-CO_2 in Mongolia. (Energy Charter et al. (2014) mentioned 187Gt-CO_2 reductions, but we suspect a unit calculation error.)

Figure 31 Gobitec and Asia Super Grid concept

a) Possible interconnections of the ASG



b) Generation mix of 2030 and *Gobitec* capacity



Source: Energy Charter, et al. (2014).

Table 5 Total construction investment and operation & maintenance costs

	Construction cost [Million USD]	Annual O&M cost [Million USD/year]
Gobitec	237 900	5 948
Asian Super Grid (ASG)-Total	56 710	1 418
ASG+Gobitec collecting system	34 562	864
Mongolia side collecting system	235	6
Russia side collecting system	666	17
China side collecting system	16 750	419
Korea side collecting system	1 476	37
Japan side collecting system	3 021	76
Sum	294 610	7 366

Source: Energy Charter, et al. (2014). APERC reproduces the table based on the information in the source.

Table 6 Total supply unit cost estimation and comparison with weighted average electricity charge of importing countries

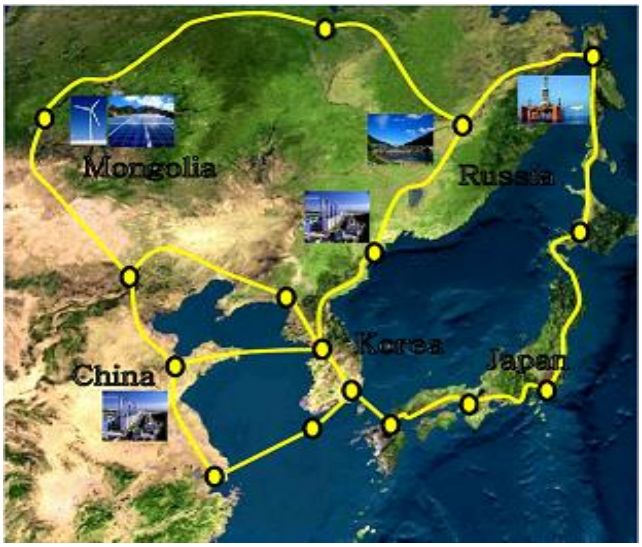
	Capacity factor of renewables (solar+wind farms)				
	20%	30%	40%	50%	60%
a. Annual sales energy amount [TWh/year]	162	243	234	438	525
b. Total annual cost [Millions USD/year]	32 402	32 402	32 402	32 402	32 402
Total supply unit cost (=a/b/1000) [USD/kWh]	0.200	0.133	0.100	0.080	0.067
Weighted Average Electricity Charge [USD/kWh]	0.136	0.125	0.120	0.117	0.115

Source: Energy Charter, et al. (2014). APERC reproduces the table based on the information in the source.

3.1.6. NEA SUPER GRID (KEPCO)

KEPCO features a super grid team in its power grid planning department, which is actively working on the super grid concept as well as attending international symposiums (JREF, 2014; Energy Charter, 2014a) and participating in international research activities (see also Section 3.1.7). KEPCO maintains an overall picture of the super grid as shown in Figure 32, which is intended to integrate diverse energy sources, share peak load among related regions and realise a reliable power system.

Figure 32 Northeast Asia Super Grid concept



Source: KEPCO (2014a).

3.1.7. NORTHEAST ASIA SUPER GRID (SKOLTECH)

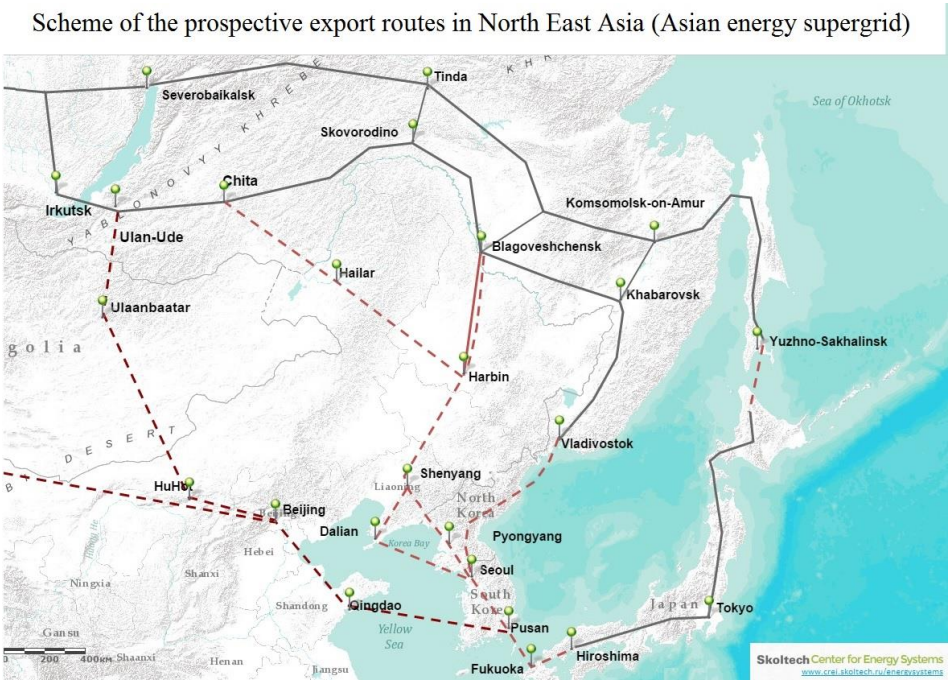
The Center for Energy Systems at the Skolkovo Institute of Science and Technology (Skoltech)—a private graduate university in Skolkovo, a suburban area of Moscow—started research on modelling and analysis of the so-called 'super grid' or 'Asian Energy Ring' in the framework of a memorandum signed between Skoltech, the En+ Group and KEPCO (Korea) during Russian President Vladimir Putin's visit to Korea in November 2013 (Skoltech, 2014b).

Since then, researchers from Skoltech and Melentiev Energy Systems Institute, Siberian Branch of the Russian Academy of Science (ESI SB RAS) have studied the potential benefits of the super grid concept as illustrated in Figure 33. This research seeks to develop options for electricity exports from Russia to countries in NEA. As depicted in Figure 33, three alternative routes from Russia to Korea are considered: a submarine cable connection from Dalian (China) and two transmission lines through DPRK. The project's profitability might substantially increase with Japan's participation with supplies undertaken by the northern (undersea cable from

Sakhalin) and southern (undersea cable from Korea through Kyushu to Honshu islands) routes. (Skoltech, 2014a; Skoltech & ESI SB RAS, 2015).

On April 2015, Skoltech hosted an international workshop on the Asian energy super grid project, during which they presented results of the research conducted by Skoltech in conjunction with the ESI SB RAS and supports of KEPCO and En+ group. Skoltech presented simulation results showing the benefits of power grid interconnection in the region. Calculated annual benefit is 24.4 billion USD/year in the "Limited integration scenario" (Skoltech & ESI SB RAS, 2015). This scenario takes into account energy security concerns of individual economies.

Figure 33 Northeast Asia Super Grid concepts



Source: Skoltech & ESI RAS (2015).

3.2. BILATERAL INTERCONNECTION CONCEPTS

Several organisations in the relevant regions are working on bilateral interconnections in order to realise the NEA-wide grid interconnection concept (see Section 3.1). We also conducted a survey regarding these bilateral interconnection activities over the last few years, which are summarised in Table 7.

According to our survey, Korean and Russian organisations, including KEPCO, Inter RAO and FGC UES, are working actively to expand cross-border power trades. KEPCO has signed the aforementioned MOU with Skoltech and the En+ Group in November 2013, and Korea's master plan mentioned that Korea-Russia connection should be considered as a future potential project if it is profitable and DPRK situation improves (MOTIE, 2014). The SGCC (China) and Russia's grid company signed a strategic cooperation agreement in May 2014 with the Chinese Premier Xi Jinping and Russian President Vladimir Putin in attendance. By contrast, involvements of Japan side is limited; several telecommunication companies and trading companies have shown their interests, yet electric power utilities --which owns transmission network until the legal unbundling (April 2020)-- have not been involved in the discussions.

The relevant organisations have commenced a feasibility study (F/S) on Korea–Russia (through DPRK), Japan–Korea and Japan–Russia (Far East) interconnections. The group of Korean and Russian organisations above (KEPCO, Skoltech and En+) as well as Melentiev Energy System Institute (ESI SB RAS) has quantitatively discussed Korea-Russia route as a part of NEA-wide super grid (Skoltech & ESI SB RAS, 2015). KEPCO (2014a) presented that 'Pre-Feasibility Study' is ongoing for the Japan–Korea route discussions, and Nikkei (2013) reported that a group of Japanese and Russian companies plans to conduct a F/S to evaluate the project's profitability. Concerning the China–Korea interconnections, KEPCO mentioned that they are interested in joint research with the Chinese side (KEPCO, 2014b). As of mid-2015, most of the concepts do not specify a power plant type for generating the energy to be exported/imported, with several concepts proposed as follows:

- China–Russia: Thermal power (Smirnov, 2012), coal-fired (Asiam Research Institute, 2014) and hydro power (RusHydro, 2014); Russia exports to China in these concepts.

- Japan–Russia: Hydro power (Nikkei, 2013) from Russia's Far East region or coal/gas-fired from the Sakhalin region to Japan.

Table 7 Major concepts and progress, interconnection routes

Route	Related organisations	Source/Quick descriptions	Progress	Barriers
China–Korea	**Korea Electric Power Corporation (Korea)**	• Presentation at international symposiums (KEPCO, 2014a; KEPCO, 2014b) • **Concept:** Connect western Gyeonggi-do area to eastern China (3GW HVDC line).	Proposal	• Involvement by China
China–Russia	**Federal Grid Company of United Energy System (Russia)**	• Presentation at an international conference (Kazachenkov, 2012)	Proposal	• Pricing agreement • Transmission infrastructure in Russia IPS-East
	Inter RAO (Russia)	• Presentation at an international conference (Smirnov, 2012) • **Concept:** Export power generated by Russia's thermal plants to China.	Study phase	
	Federal Grid Company of United Energy System (Russia) **State Grid Corporation (China)**	• ROSSETI's company news (ROSSETI, 2014) • The two companies signed a strategic cooperation agreement.	Cooperation agreement signed	
	Inter RAO (Russia)	• Reports by Asiam Research Institute (Asiam Research Institute, 2014) • **Concept:** Inter RAO builds the largest coal-fired plants (8GW) in the Far East region to export power to China.	Study phase	
	RusHydro (Russia) **Three Gorges Corporation (China)**	• RusHydro company news (RusHydro, 2014) • The parties signed a preliminary agreement to establish a joint venture to construct up to 2GW hydro plants in Russia and evaluate the power export potential to China.	Cooperation agreement signed	

Route	Related organisations	Source/Quick descriptions	Progress	Barriers
Japan–Korea	**Korea Electric Power Corporation (Korea)**	• Presentation at international symposiums (KEPCO, 2014a; KEPCO, 2014b) and report by Korea JoongAng Daily on KEPCO's interests (JoongAng, 2014) • **Concept:** Connect Gyeongnam area to Fukuoka (2GW HVDC line).	Pre-F/S phase	• Involvement by Japan (power utilities/public bodies)
Japan–Russia	**Inter RAO (Russia)** **Mitsui Corporation (Japan)** **Softbank (Japan)**	• Nikkei reported the group started F/S (Nikkei, 2013) • **Concept:** Russia's Far East region exports hydro power to Japan. • Overall investment costs to be calculated within 2014.	Study phase (no updates available since 2013)	• Long transmission distance (if the Far East region and Hokkaido are connected via Sakhalin) • Large investment needed for transmission system in the Far East region.
	Inter RAO (Russia)	• Presentation at an international symposium (Inter RAO, 2014) • **Concept:** Sakhalin region exports coal-fired/gas-fired power to the Hokkaido and Honshu areas. • Total capacity: Up to 3GW.	Proposal	
	RAO Energy System of East (Russia)	• Presentation at an bilateral symposium (RAO Energy System of East, 2014) • **Concept:** Build an energy bridge between Russia's Far East area, Sakhalin and Japan. 2–4GW electricity export to Japan. • Three stages project: (1) Connect Hokkaido and Sakhalin, (2) Construct power plant in Sakhalin, and (3) connect Sakhalin and 'mainland' Russia.	Proposal (Pre-F/S expected in November 2014)	

Route	Related organisations	Source/Quick descriptions	Progress	Barriers
Korea–Russia (through DPRK)	**Ministry of Trade, Industry & Energy (Korea)**	• Mentioned in Korea's Energy Master Plan (MOTIE, 2014) • **Concept:** Korea imports low-cost electricity from Russia. • Two plans proposed, 2–5GW HVDC tie lines. • Conduct joint study by Korean and Russian private sectors.	Study phase (conducted by private sector)	• Security issues related to DPRK • Long transmission distance
	Korea Electric Power Corporation (Korea) **En+ (Russia)** **Skoltech (Russia)**	• Presentation at international symposiums (KEPCO, 2014a; KEPCO, 2014b) • **Concept:** Connect Vladivostok to North Gyeonggido with HVDC 500kV–800kV tie line. • MOU signed. F/S is on-going.	MOU signed Pre-F/S phase	
	Federal Grid Company of United Energy System (Russia)	• Presentation at an international conference (Kazachenkov, 2012)	Proposal	

HVDC = high-voltage direct current; F/S = feasibility study.

3.2.1. CHINA–KOREA ROUTE

As described in Figure 34, KEPCO presented their grid interconnection concepts, including a China–Korea route, at several international symposia (KEPCO, 2014a; KEPCO, 2014b). They propose to connect Western Gyeonggi-do area and the eastern part of China via HVDC 500kV lines with 3GW capacity. KEPCO mentioned their interest in a joint study on this route with the Chinese side.

Figure 34 China–Korea interconnection concept

Source: KEPCO (2014b).
Note: This figure shows the China–Korea route as well as Japan–Korea and Korea–Russia routes.

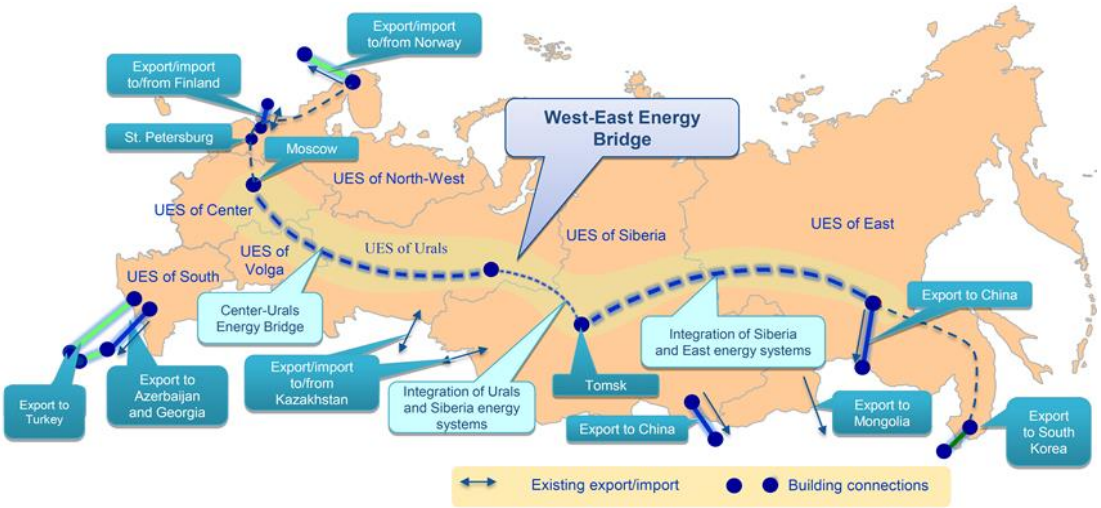
3.2.2. CHINA–RUSSIA ROUTE

China and Russia have already been interconnected, and historically, Russia has exported electricity to China. Annual cross-border electricity exports are approximately 2.63TWh and 3.50TWh in 2012 and 2013, respectively. Russian companies, including Inter RAO, FGC UES and RusHydro, work actively to expand their power trade opportunities. As mentioned in Table 7, several proposals and activities have been observed in the last few years. Historically, Russian stakeholders mainly presented their power trade concepts; however, recently, stakeholders in both countries have started actively working and signed some corporation agreements (such as those between SGCC and FGC UES and between RusHydro and China Three Gorges Corporation).

In 2012, FGC UES presented the 'energy bridge' concept (Figure 35). This concept includes interconnections between west and east Russia as well as between Russia and neighbouring regions, including NEA.

Moreover, Inter RAO also presented three future options in 2012 to expand the electricity trade between China and Russia. The first option involved exporting thermal power (3.6GW scale) from Amur Oblast to Shenyang, with an estimated annual export amount of 18TWh. The second option entailed exporting 7–7.5GW-scale thermal power from Amur Oblast to Beijing, with approximately 38TWh in annual exports (Figure 36a)). The last option involved the second option as well as power flows from the Buryatia and Zabaykalsk regions, with total annual exports of 76TWh (Figure 36b)).

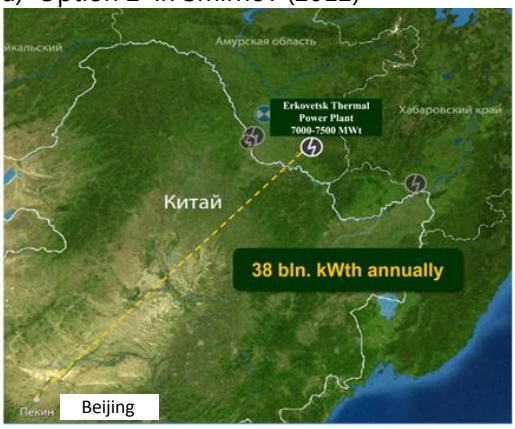
Figure 35 Prospects for energy bridge development, Russia



Source: Kazachenkov (2012).

Figure 36 Possible future China–Russia interconnection options, as of 2012

a) 'Option 2' in Smirnov (2012)



b) 'Option 3' in Smirnov (2012)

Source: Smirnov (2012).
MWt =megawatt; kWth =kilowatt hour; bln. = billion.

In May 2014, Russian grids and the SGCC signed a strategic cooperation agreement with the Chinese Premier Xi Jinping and Russian President Vladimir Putin in attendance (ROSSETI, 2014). This agreement opened the way to exploring the possibility of a European–Asian energy bridge and supplying electricity to China. Further, these companies agreed to discuss the possibility of constructing UHV (Ultra High Voltage) transmission lines—both AC (alternating current) and DC (direct current)—and EHV (Extra High Voltage) sub-stations in Russia.

Furthermore, also in May 2014, the Asiam Research Institute reported that Inter RAO conducted a F/S to build the world's largest coal-fired power plant and export its electricity to China (Asiam Research Institute, 2014). According to this article, Inter RAO studied the costs and lead times of a plant with 8GW capacity, and analysts estimated that the project would cost approximately 12 billion USD. This plan requires that the plant's coal resources be sourced from Erkovetskaya.

In November 2014, Russia's largest hydropower producer, RusHydro, announced the signing of a preliminary agreement with the China Three Gorges Corporation (RusHydro, 2014). The agreement mainly focused on the establishment of a joint venture, with RusHydro having 51% ownership, to build and operate up to 2GW hydro power plants in Amur Oblast and Khabarovsk Kray in Russia (total cost of the projects estimated as 230 billion RUB). RusHydro will conduct detailed F/Ss for each project and examine the electricity export potential to China.

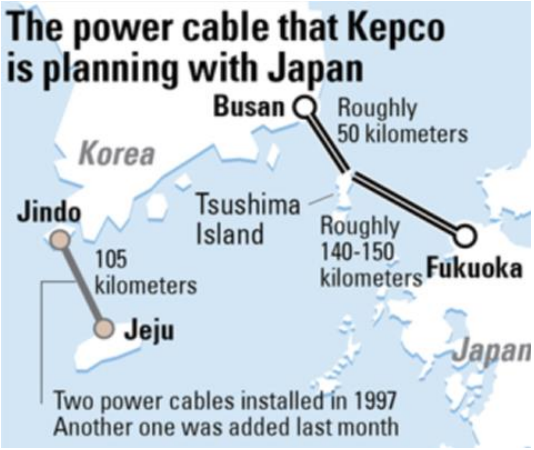
However, according to Sakai (2014), power transmission from Russia to China has been disrupted twice because of delays in reaching a power-trade price agreement. Price issues would be an important agenda for expanding interconnections between these economies.

3.2.3. JAPAN–KOREA ROUTE

KEPCO has a concept to connect Gyeongnam area and Fukuoka via 500kV HVDC with approximately 2GW capacity (Figure 34). The route would be approximately 200km long, and KEPCO emphasises its technical feasibility based on their experience (they have successfully installed two power cables between Jindo and Jeju (105km)).

The newspaper *JoongAng* (2014) also reported this concept in August 2014 as illustrated in Figure 37. The reported route passes Tsushima Island (Japan). In that case, the 200km submarine route is roughly divided into a 50km segment (Busan–Tsushima) and 150km segment (Tsushima–Fukuoka). The article also noted that Softbank's chairman Masayoshi Son has shown an interest in the project as the first step towards realising the Asia super grid concept (see Sections 3.1.3 and 3.1.5).

Figure 37 Japan–Korea interconnections route



Source: Korea *JoongAng* Daily (2014).
Note: 'last month' in this figure is July 2014. This figure does not necessarily reflect KEPCO's plan.

3.2.4. JAPAN–RUSSIA ROUTE

In February 2013, Nikkei (2013) reported that a group of Japanese and Russian companies (Inter RAO, Mitsui Corporation and Softbank) commenced a F/S on interconnections between Japan and Russia's Far East region (Figure 38a)). Their proposal is based on Japan importing hydro electricity from Russia's Far East region. The group intended to calculate overall investment costs during 2014 and accordingly decide whether to continue negotiations. Nikkei pointed out some challenges, including laws/regulations revision, concerns for stable supply and huge investment needs.

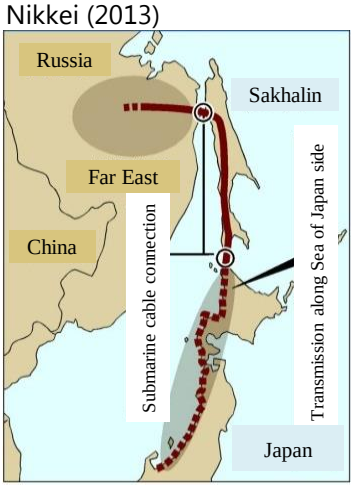
In January 2014, Inter RAO (2014) 're-'proposed a different concept to connect Hokkaido and Sakhalin. Coal-fired and gas-fired power plants in the Sakhalin region are planned to be primary power supply sources to Japan (Figure 38b)). Total capacity will reach up to 3GW, comprising three power plants: two 1050MW-scale coal-fired plants and one 800MW-scale gas-fired plant. The proposed connection points are Cape Crillon, Korsakov and Uglegorsk on the Sakhalin side and Cape Soya/Wakkanai city on the Hokkaido side. They further proposed to connect Hokkaido to Niigata (located on Japan's main island) via a submarine cable.

According to Inter RAO (2013), the idea of building an 'energy bridge' between Hokkaido and Sakhalin islands was originally proposed by RAO UES in 1998. The Russian side jointly conducted a pre-F/S with Marubeni Corporation (Japan) in 1999 and signed a protocol of cooperation with Sumitomo Corporation (Japan) in 2003. However, no further progress has since been achieved.

In September 2014, at the second Japan–Russia Forum held in Moscow, RAO Energy System of East[8] presented four prospective energy cooperation fields (RAO Energy System of East, 2014). They proposed the Japan–Russia energy bridge concept, comprising three phases as shown in Figure 38c): (1) construct transmission lines between Hokkaido and Sakhalin islands, (2) install a 1GW-scale power plant and additional transmission lines (500kV) in Sakhalin, and (3) construct a connection between Sakhalin and 'mainland' Russia (500kV DC submarine cables). Total power transmission scale would be 2–4GW.

Figure 38 Japan–Russia interconnection concepts

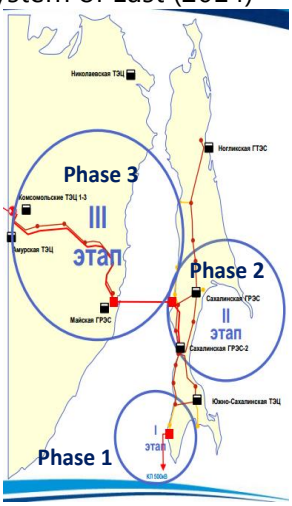
a) Nikkei (2013)



b) Inter RAO (2014)

Power-generation units construction plan:
- Total capacity: Up to 3 GW
- Realization in three stages
  - First stage: coal-fired power plant, 1050MW
  - Second stage: coal-fired power plant, 1050MW
  - Third stage: gas-fired power plant, 800MW

c) RAO energy system of East (2014)



Phase 1
- Submarine cable construction (La Pérouse Strait).
- Construction of power receivers and transmission lines at Hokkaido isl.

Phase 2
- Power plant construction for power exports or the extension of existing power stations under 1GW.
- Additional transmission line construction (500kV) in south Sakhalin.

Phase 3
- Operation of two submarine 500kV DC cables between Sakhalin and 'mainland' Russia to export electricity from IPS-East.

2-4GW power export is expected. A pre-feasibility study is expected in November 2014.

Sources: Nikkei (2013), Inter RAO (2014) and RAO Energy System of East (2014).

[8] RAO Energy Systems of East was founded in July 2008 to manage the energy companies operating in the United Energy System of East (Primorsky Krai, Khabarovsk Krai, Amur Oblast, Jewish Autonomous Oblast, and South Yakutia) as well as in six isolated energy systems (RAO Energy System of East, 2015).

3.2.5. KOREA–RUSSIA ROUTE

Several research institutes have studied the Korea–Russia route for more than ten years (see Section 3.1.1). In January 2014, Korea's Energy Master Plan mentioned two possible approaches to grid interconnection with Russia (Figure 39). The main concept involves importing electricity at a low cost due to Russia's abundant resources. The plan mentioned that the Korean and Russian private sectors should conduct a joint study, whereas the master plan mentioned that 'the concept should be considered as a prospective mid- to long- term governmental project if the joint study concluded that it is profitable and if the overall conditions, including inter-Korean relations, improve' (MOTIE, 2014). Plan 1 is a Korea–DPRK–Russia HVDC link, supplying power in the DPRK. The proposed HVDC capacity is 2–5GW, and transmission length will be approximately 1,200km. Plan 2 is a direct connection between Korea and Russia via HVDC with a capacity of 3–5GW. Transmission length will be approximately 1,000km.

Figure 39 Korea–Russia interconnection plans in Korea's Energy Master Plan

Source: MOTIE (2014).

4.MODELLING AND ANALYSIS OF GRID INTERCONNECTIONS

Referring to the literature summarised in the previous sections, we developed a multi-region power system model (Linear Programming model) and macroscopically examined the potential benefits of power grid interconnections in NEA.[9] This section explains the methodology and assumptions as well as the results.

4.1. METHODOLOGY: A MULTI-REGION POWER SYSTEM MODEL

We developed a multi-region power system model using linear programming techniques. Figure 40 presents a schematic diagram of this model. This model aims to minimise a single-year overall system cost, consisting of the annualised initial cost, operation and maintenance (O&M) cost, fuel cost and carbon cost of the whole NEA, under various technical and political constraints. Hence, the NEA economies are assumed to fully cooperate to achieve the regional optimisation. The model considers several power-generation technologies such as nuclear, coal-fired, gas-fired, oil-fired, hydro, solar photovoltaics (PV) and wind; pumped hydro storage as a storage facility; and High-voltage (HV) line/cable technology as transmission line technology. A detailed mathematical description of the model is provided in Appendix A.1. Validation of the model is discussed in Appendix A.2.

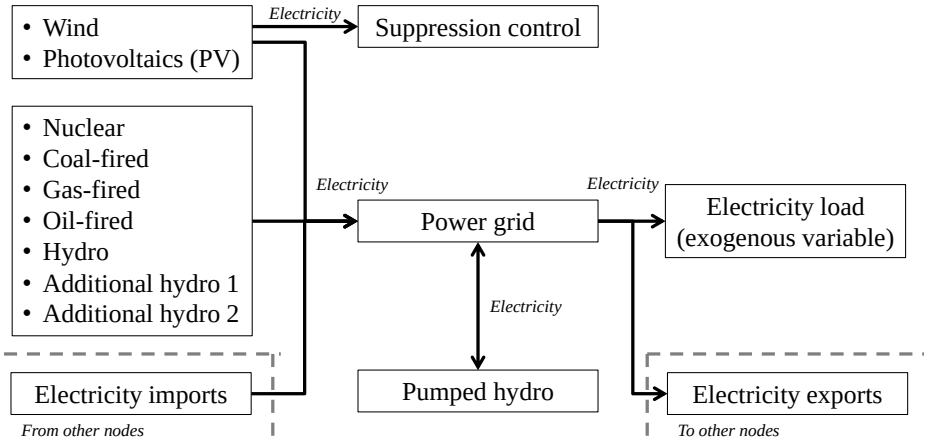
A capital recovery factor is used to annualise initial investments in generation, storage and cross-border transmission facilities. The assumed discount rate is 3% and lifetime assumptions are discussed in Section 4.3.2 and 4.3.3. O&M cost includes both fixed and variable O&M cost. Fixed O&M cost, which is incurred even if the plant was not operated (i.e., landowner cost), is assumed to be in proportion to capacity, while variable O&M cost (i.e., consumables) varies with generated electricity. Carbon cost in this study considers direct emissions from fuel combustions.

The cost of generation includes initial cost, fixed and variable O&M cost, fuel cost and carbon cost. The cost of cross-border transmission lines includes initial cost and

[9] Large parts of Section 4-5 and Appendix A.1-A.2 are revisions of the author's journal article: '*Electric Power Interconnections in Northeast Asia: a Quantitative Analysis of Opportunities and Challenges', Takashi Otsuki, Aishah B. Mohd Isa and Ralph D. Samuelson, Energy Policy (accepted, in press)*. This article which will be published as an open access article (license: CC BY 4.0). APERC would like to sincerely thank Energy Policy (Elsevier journal) and four anonymous journal referees for their helpful suggestions for improvements. Note that the results in this report are slightly different from the journal article due to different model setups. For example, this report considers the Russia-Siberia node as a city node (Figure 41), while the journal article considers it as a supply node.

fixed O&M cost. Power trade is selected by its benefit (usually the savings in generation cost) is larger than the cost of cross-border transmission lines.

Figure 40 Multi-region power system model, schematic diagram



Source: APERC analysis.

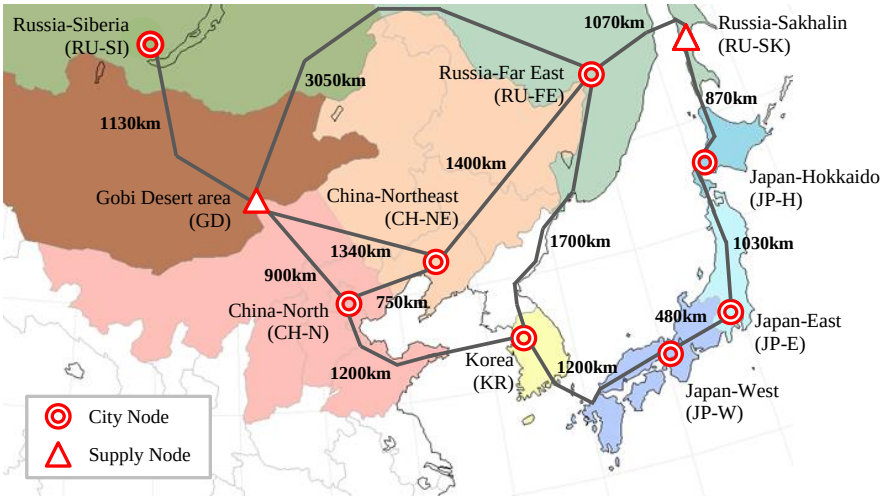
This model is formulated in a consistent way in the General Algebraic Modelling System (GAMS) software. There are 75 thousand equations or constraints and 38 thousand endogenous variables. For our modelling work, we referred to the detailed modelling approach in Schaber, et al. (2012), Komiyama & Fujii (2014) and Komiyama, et al. (2015), but due to data availability we selected the temporal and geographical resolution as explained below.

Regarding the temporal resolution, the model considers the hourly load curves of typical days for five seasons (Summer-peak, Summer-average, Winter-peak, Winter-average and intermediate) in order to model the diversity of seasonal and daily load variation among the regions. Thus, in each node, one calendar year is decomposed into 120 time segments (= 24 hours per day × 1 representative day per season × 5 seasons per year).

As for the geographical resolution, we divide NEA into ten nodes (Figure 41), represented by eight city nodes (round markers) and two supply nodes (triangle markers). City nodes have electricity demand and power supply facilities, while supply nodes can have only power supply facilities to export electricity. Initial capacity of supply nodes are set to zero in this analysis, and endogenous capacity additions are allowed in both types of nodes. Six of the city nodes correspond to power grid or power service areas: North China grid (CH-N); China Northeast grid (CH-NE); Japan Hokkaido area (JP-H); Korea (KR); Russia Far East power system (RU-FE), and Russia Siberia power system (RU-SI). The Tohoku and Tokyo areas in Japan are aggregated as JP-E, and the western parts of Japan as JP-W. Supply nodes consist of the Gobi Desert area in Mongolia (GD) and the Russia Sakhalin area (RU-SK), which have relatively abundant energy potential (wind and solar in GD, and coal and gas in RU-

SK) compared to its electricity demand. Electricity demand in the supply nodes is simplified in this analysis; however, we believe our model is detailed enough to reflect the key drivers of costs and benefits of grid interconnections as market size of Sakhalin and Mongolia are much smaller that Hokkaido area –the smallest modelled city node– by a factor of nine to seventeen (Saneev & Sokolov, 2015; RAO Energy System of East, 2015; HEPCO, 2015).

Figure 41 Regional division and assumed transmission distances



Source: APERC analysis.

We modelled electricity transmission as a transport problem. Kirchhoff's first law (conservation of current) is considered in each node of the network, but the second law (voltage law) is not incorporated. This simplified approach allows us to keep the optimisation problem linear and to optimise grid extensions, generation expansion and operations simultaneously (Schaber, et al., 2012). Distances between nodes in Figure 41 were based on airline distances between representative cities in each region plus 20% to allow for expected circuity (Google, 2015). Regarding the transmission between KR and RU-FE, there are significant diplomatic challenges involved in arranging transit across the DPRK. However, we take this route into account as the Korea Energy Master Plan explicitly mentions that the connection "should be a prospective mid- to long-term governmental project" if it is profitable and overall conditions, including inter-Korean relations, improve (MOTIE, 2014).

4.2. SCENARIO SETTINGS

We examine the five scenarios in Table 8. The simulated year in this study is 2030. The *Base* scenario assumes no grid expansion from the existing transmission line capacity. In the *NoNewRE* scenario, new interconnections are allowed based on total system cost optimisation, but renewable capacity is fixed to the *Base* scenario assumptions at all nodes. The *RuHyd* scenario endogenously allows additional hydro power

development in the Russian nodes. As hydro power developments for Russian domestic supply are already considered in the initial capacity settings in Figure 43, we assume that the additional hydro plants are used only for exports to the foreign nodes in this study. The *Gobitec* scenario attempts to quantify the costs and benefits of the "*Gobitec/ASG*" concept proposed by Energy Charter et al. (2014)[10]. They targeted 50GW of wind and 50GW of solar PV in GD (the Gobi Desert) by 2030. The last scenario (*Gobitec+RuHyd*) considers both the *Gobitec* and the *RuHyd* assumptions. The assumed carbon price is 30 USD/*t*-CO_2 for all scenarios. Further explanations of the assumptions, including the limits for fossil fuel capacity additions and additional hydro potential in Russia, are given in Section 4.3.

Table 8 Scenarios, definitions

Scenario	*Base*	*NoNewRE*	*RuHyd*	*Gobitec*	*Gobite+RuHyd*
Fossil fuel-fired capacity	Cost optimised for all scenarios. For coal-fired plants, we impose upper bounds based on the projected capacity in APERC (2013b), reflecting environmental concerns.				
Wind/PV capacity	Projected capacity for 2030 (APERC, 2013b)			Gobi Desert (GD): 50GW solar, 50GW wind (Energy Charter, et al., 2014). Other nodes: same as *Base* scenario	
Hydro capacity	Projected capacity for 2030 (APERC, 2013b)		Endogenous additions allowed in Russia nodes for export (see Section 4.3.4). Other nodes: same as *Base* scenario	same as *Base* scenario	same as *RuHyd* scenario
Inter-connection	Current capacity	Cost optimised for the last four scenarios			
Carbon price	30 USD/t-CO_2 for all scenarios				

Source: APERC analysis.
Note: PV=photovoltaic.

Kunstýř & Mano (2013) investigated the security risks for Japan of importing electricity from Russia. They concluded that the power trade would not pose substantial security risks for Japan with the appropriate measures, such as ensuring a capacity buffer at the current level. In general, each service area needs to be prepared for cross-boundary transmission interruptions. Therefore we limit the share of net transmission inflows at each city node to be less than the reserve margin level as described in Equation (A.23) in Appendix A.1.

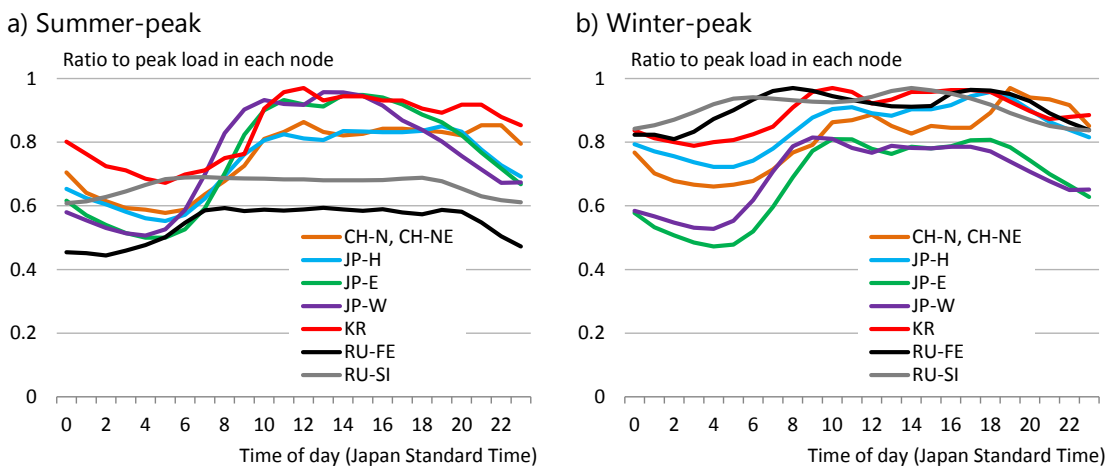
[10] To our knowledge, they do not mention the reason for their choice of this level of capacity, but there seems to be a consideration of energy security risk (Mano, 2014). The land area of 50GW solar PV capacity would account for approximately 0.1% of the Gobi Desert area, assuming that total Gobi Desert area is 1,300,000km^2 and the land area required for solar PV cells is 20km^2/GW (Eurus Energy, 2012).

4.3. INPUT DATA ASSUMPTIONS

4.3.1. ELECTRICITY DEMAND AND LOAD CURVES

Our analysis considers the seasonal and diurnal characteristics of electric load in each node. We estimated electricity demand in 2030 from each node's historical data (JEPIC, 2013; The Government of Japan, 2014) and the projected growth rate from APERC (2013b). We also constructed daily load curves for the five seasons from available historical load curve information and load factor data (JEPIC, 2006; SO UPS, 2014; Nagayama, 2014; The Government of Japan, 2014). Figure 42 depicts the estimated daily load curves in the Summer-peak and Winter-peak seasons[11]. Note that all the curves are plotted in Japan Standard Time. Time differences among the modelled city nodes are a maximum two hours[12]. Japan and Korea are located in the same time zone. Compared to these two regions, China and Russia Siberia area (Irkutsk time) is one hour behind, while Russia Far East area (Vladivostok time) is one hour ahead. The peak load season varies by node; for example, the peak load season is summer in JP-E and JP-W and winter in Russia nodes. The daily load curve in Japan is characterised as 'mountain-shaped' mainly due to daytime consumptions in commercial sector; by contrast, the daily load curve in Russia is relatively levelised but it shows large seasonal variations due to due to heating demand in inter period.

Figure 42 Estimated daily load curve (ratio to peak load), city nodes



Sources: JEPIC (2006), The Government of Japan (2014), SO UPS (2014).

[11] Due to data availability, the same load curve is assumed for CH-N and CH-NE.

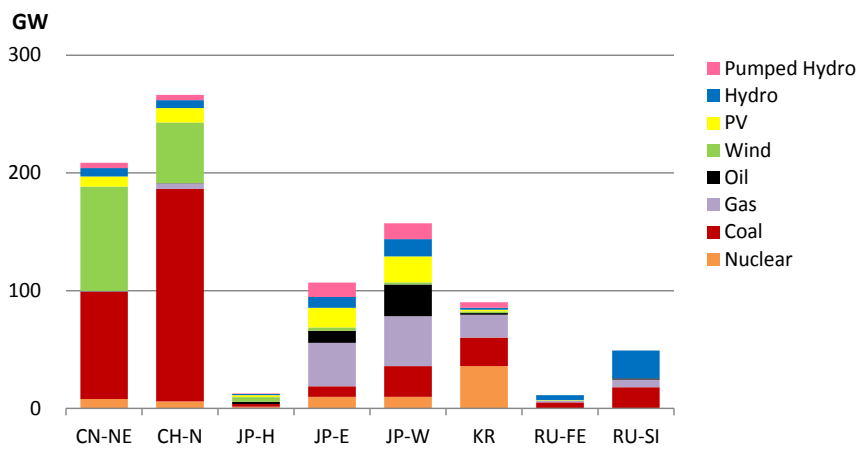
[12] None of the modelled city nodes in China, Japan, Korea and Russia use daylight saving time (DST) as of September 2015. Mongolia does use DST, but the wind and solar output curves in Figure 45~Figure 46, as well as all of our other calculations for the Gobi Desert (GD), are in Mongolia Standard Time, which is the same as the time at the China nodes.

4.3.2. GENERATION AND STORAGE FACILITIES CAPACITY

The model is allowed to endogenously add fossil fuel-fired generation capacity in the all scenarios. Capacities for nuclear, solar PV and wind are given exogenously in each scenario. Hydro plant capacities are exogenous variables, except for RU-SI and RU-FE in the *Ruhyd* and *Gobitec+RuHyd* scenarios. Assumptions for additional hydro potential for these nodes are discussed in Section 4.3.4. Figure 43 depicts initial capacity settings for generation and storage facilities.

The initial capacity of fossil fuel-fired plants and pumped hydro are based on existing capacities in 2011 (JEPIC, 2014a; Hippel, et al., 2011). For coal-fired plants, we impose upper bounds based on the projected capacity in APERC (2013b), reflecting environmental concerns. The initial capacity for renewables, except for GD (the Gobi desert area), is estimated based on the projected capacity for 2030 in APERC (2013b) as well as renewable energy potential (McElroy, et al., 2009; Energy and Environment Council, 2011). For renewables in GD in the *Gobitec* and *Gobitec+RuHyd* scenarios, we assumed 50GW of PV and 50GW of wind turbines (Energy Charter, et al., 2014). For nuclear generation, we estimated the capacity in 2030 based on available information (JAIF, 2013; MOTIE, 2014).

Figure 43 Initial capacity assumptions



Sources: METI (2013b), JAIF (2013), FEPC (2014b), Hippel, et al. (2011), JEPIC (2013).
Note: PV = photovoltaic.

COSTS, EFFICIENCY AND AVAILABILITY

Table 9 ~ Table 13 show the assumptions for generation and storage facilities. We set the assumptions in a consistent way, comparing multiple sources from international organisations, governments, industries as well as research institutes in order to ensure the validity. Specifically, the initial costs data for 2030 are estimated from IEA and individual economy analyses and projections (IEA, 2010; IEA, 2014a; METI, 2015c;

Skoltech & ESI SB RAS, 2015). The future Initial cost of fossil fuel-fired plants and wind power remain similar to the current level, while solar PV shows drastic cost reductions[13]. Annual fixed O&M cost [USD/kW/year] are estimated based on EIA (2013), IEA (2014a) and METI (2015c). For variable O&M cost (except fuel costs), in Japan we assumed 2 USD/MWh for nuclear, 5 USD/MWh for coal-fired, 6 USD/MWh for gas-fired and 4 USD/MWh for oil-fired plants (EIA, 2013; METI, 2015c). In other regions, we adjusted the variable O&M cost using the ratio of initial cost between Japan and each region. The carbon content of each fuel type is derived from EDMC (2014). Assumptions for own-use of electricity at generating plants, ramp-up/down rate, minimum output level and conversion efficiency are taken from IEA (2014b; 2014c) and METI (2015c).

In considering the maximum availability for nuclear, fossil fuel-fired and hydro generation, we estimated the values using historical capacity and generation data (JEPIC, 2013; EDMC, 2014; KESIS, 2015). We confirmed that the model reproduces results similar to the actual power system (see Appendix A.2). As for wind and PV, hourly output profiles are given exogenously. We estimated those output profiles for GD (the Gobi Desert) as explained later in this section. Because of the limited meteorological information available for some economies, the daily output profiles for other areas rely on the following simple assumptions: the daily output profile for wind is kept flat at all time in all seasons assuming 20% capacity factor, and, for PV, hourly output profiles in each season are assumed from the observed or estimated profiles in Zhao et al. (2009) and Shiraki et al. (2011). Also, please note that the output of hydro power is kept flat among the seasons (see equation (A.12)) assuming 40% capacity factor, and seasonal variation is not considered in this study.

Fossil fuel price assumptions in 2030 in Table 14 have been determined from the best available projections (IEA, 2010; Shinoda, 2013; MUFJ, 2013; Morita, 2013; Ling, 2013; KESIS, 2015). We based these estimates on historical CIF prices for energy importing economies, historical FOB prices for exporting economies, and future import price trends from IEA WEO (2013). We conduct the simulations in Sections 4.4.1~4.4.5 under the fossil fuel price assumptions. However, the assumptions for future fuel prices include significant uncertainties given their past volatile nature over the last decade. Therefore, we conducted a sensitivity analysis of future energy prices in Section 4.4.6.

[13] IEA (2014a) shows the projected initial cost in 2020 and 2035, and, for example, the initial cost of large scale solar PV in China is projected to decrease by approximately 40% by 2035 compared to the 2012 level.

Table 9 Assumptions for generation and storage facilities

	Nuclear	Coal	Gas	Oil	Hydro	Wind	PV	Pumped
Life time [year]	40	40	40	40	60	20	20	60
Carbon content [t-CO_2/toe]	0	3.8	2.1	2.9	0	0	0	0
Own-use rate [%]	4	6	3	5	-	-	-	-
Maximum ramp-up / down rate [%/h]	0	30	50	100	-	-	-	-
Capacity credit [%]	90	90	90	90	40	25	15	85
Minimum output level [%]	100	30	20	15	-	-	-	-
Cycle efficiency (storage) [%]	-	-	-	-	-	-	-	75
Self-discharge rate (storage) [%/hour]	-	-	-	-	-	-	-	0.01

Sources: EDMC (2014), IEA (2014b; 2014c), METI (2015c).

Table 10 Cost assumptions for North China (CN-N), China Northeast (SN-NE) and the Gobi Desert area (GD)

	Nuclear	Coal	Gas	Oil	Hydro	Wind	PV	Pumped
Initial cost [USD/kW]	2 600	750	700	800	1 760	1 300	1 100	1 760
Fixed O&M cost [USD/kW/year]	65	15	14	16	30	33	17	40
Variable O&M cost [USD/kWh]	0.001	0.002	0.004	0.002	0	0	0	0
Maximum availability	0.8	0.7	0.9	0.9	0.4	Estimated output profile		0.8
Efficiency (fossil fuel plants)	-	0.40	0.50	0.37	-	-	-	-

Sources: IEA (2010; 2014a; 2014b; 2014c), EIA (2013), JEPIC (2013).

Table 11 Cost assumptions for Japan nodes (JP-H, JP-E and JP-W)

	Nuclear	Coal	Gas	Oil	Hydro	Wind	PV	Pumped
Initial cost [USD/kW]	4 000	2 400	1 150	1 900	6 000	1 700	2 500	6 000
Fixed O&M cost [USD/kW/year]	104	48	23	39	70	33	31	70
Variable O&M cost [USD/kWh]	0.002	0.005	0.006	0.004	0	0	0	0
Maximum availability	0.7	0.75	0.7	0.9	0.4	Estimated output profile		0.8
Efficiency (fossil fuel plants)	-	0.42	0.5	0.37	-	-	-	-

Sources: EIA (2013), IEA (2014a; 2014c), EDMC (2014), METI (2015c).

Table 12 Cost assumptions for Korea (KR)

	Nuclear	Coal	Gas	Oil	Hydro	Wind	PV	Pumped
Initial cost [USD/kW]	3 300	1 500	800	1 900	2 500	1 600	2 250	2 500
Fixed O&M cost [USD/kW/year]	86	30	16	39	30	40	34	30
Variable O&M cost [USD/kWh]	0.002	0.003	0.005	0.004	0	0	0	0
Maximum availability	0.95	0.9	0.9	0.9	0.4	Estimated output profile		0.8
Efficiency (fossil fuel plants)	-	0.40	0.50	0.37	-	-	-	-

Sources: IEA (2010; 2014a; 2014b; 2014c), EIA (2013), KESIS (2015).

Table 13 Cost assumptions for Russia nodes (RU-FE, RU-SI and RU-SK)

	Nuclear	Coal	Gas	Oil	Hydro	Wind	PV	Pumped
Initial cost [USD/kW]	2 800	2 200	1 000	1 200	2 500	1 500	2 000	2 500
Fixed O&M cost [USD/kW/year]	73	44	20	24	30	38	30	30
Variable O&M cost [USD/kWh]	0.001	0.005	0.005	0.003	0	0	0	0
Maximum availability	0.8	0.7	0.9	0.9	0.4	Estimated output profile		0.8
Efficiency (fossil fuel plants)	-	0.4	0.5	0.37	-	-	-	-

Sources: EIA (2013), JEPIC (2013), IEA (2014a; 2014c), Skoltech & ESI SB RAS (2015).

Table 14 Fuel prices assumption

	Coal [USD/t]	Gas [USD/MMBtu]	Oil [USD/bbl]
China	110.5	9.3	121.5
Russia	99.8		
Japan	140.1	14.4	
Korea	137.3	13.5	

Sources: IEA (2010; 2013), Shinoda (2013), Ling (2013), MUFJ (2013), Morita (2013), KESIS (2015).

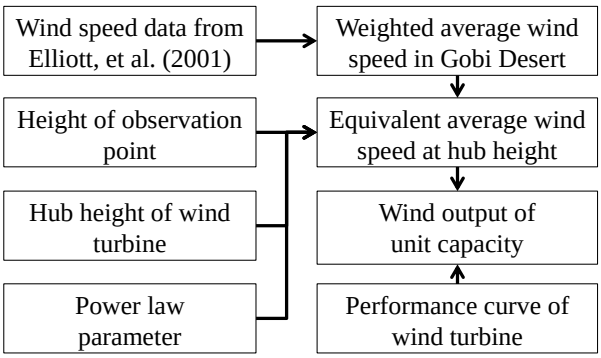
INTERMITTENT RENEWABLE ENERGY OUTPUT PROFILES IN GOBI DESERT AREA

The seasonal profile of the region-wide wind output in GD is estimated by using long-term wind observation data (Elliott, et al., 2001). We used a similar estimation approach to Komiyama, et al. (2015). Figure 44 shows a flow chart for this calculation. Elliott, et al. (2001) reports average hourly wind speed data in a day in each month at various sites. We selected five observation sites (Sainshand, Mandalgovi, Center

Tuvshin Sukh, Tumurbaatar, and Center Manlai Ummu station), and estimated the weighted average wind speed of the Gobi Desert area. Next, we estimated the equivalent wind speed at the hub height of the wind turbines using the power law, assuming that the measured wind speed is at 10m and that the n-value in the power law is eight (For discussion of the power law, see Peterson & Hennessey, Jr (1979)). Then, we calculated the hourly wind turbine output profile (Figure 45) based on the average hourly wind speed at hub height and a typical power curve.

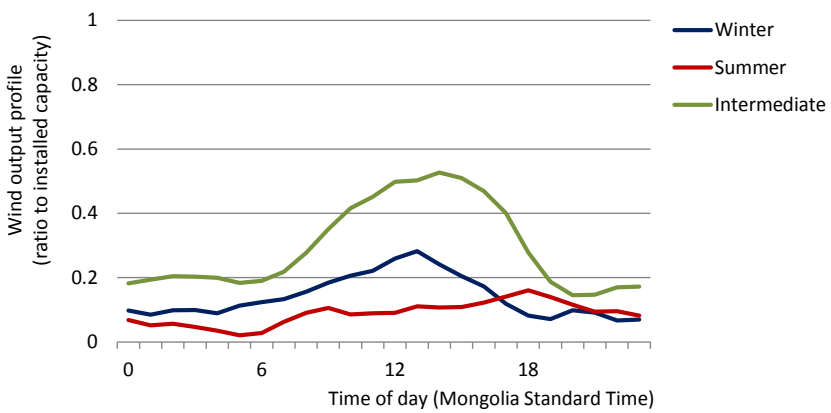
Wind speed data in January is assumed for the winter season, in July for the summer season. Wind speed in the intermediate season is estimated by averaging the data for April and October. The assumption for the hub height of the wind turbine is 80m, while the cut-in wind speed, rated speed, and cut-out wind speed are 5m/s, 12.5m/s and 25m/s, respectively. The estimated average wind capacity factor is 26%. The data in Elliott, et al. (2001) show the high wind speeds observed in the intermediate season (around April and October) in the Gobi area, and that trend is reflected in Figure 45.

Figure 44 Flow chart for the calculation of wind power output in the Gobi Desert area (GD)



Sources: Komiyama, et al. (2015) and APERC Analysis.

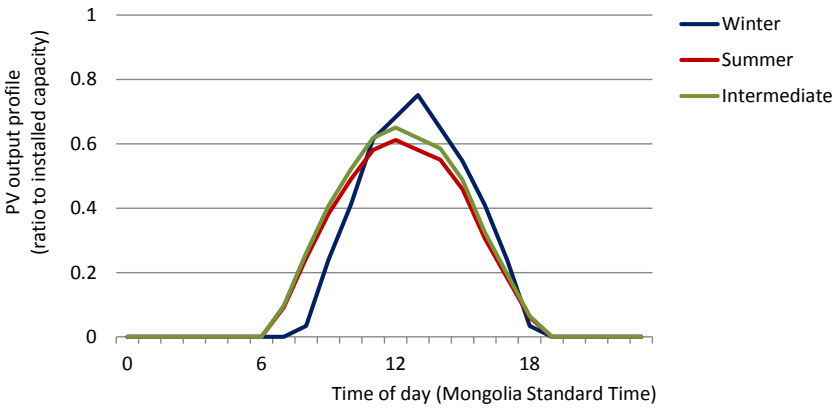
Figure 45 Assumed wind output profile, the Gobi Desert area (GD)



Source: APERC Analysis.

As for the average solar PV output profile (Figure 46), we estimated by referring to Battushig et al. (2003) and Adiyabat et al. (2005). Battushig et al. (2003) reported the average hourly maximum power of PV modules in October, November, December, March and April in the Gobi desert area. PV output profiles depend on various climatic conditions at the sites, such as sunshine duration, air mass and ambient temperature. Because of limited information about detailed solar irradiation in the area, we estimated output profiles by assuming that the observed output shape in April in Battushig et al. (2003) is the representative diurnal variation in the intermediate and the summer season in the Gobi Desert area and that the shape in December represents winter season. We then calculated the PV output profile in each season based on the shapes and the observed daily average PV energy output [Wh/day] in each season in Sainshand city in Mongolia (Adiyabat, et al., 2005).

Figure 46 Assumed Photovoltaics output profile, the Gobi desert area (GD)



Source: APERC Analysis.
Note: PV = photovoltaic.

4.3.3. TRANSMISSION LINES

Costs of HVAC overhead lines are assumed for overhead interconnections, except for the KR~RU-FE connection, where HVDC technology is proposed in governmental publications (MOTIE, 2014). For undersea connections, HVDC cable technology is assumed. Regarding HVAC substation/switching stations, one substation/switching station is assumed to be installed for every 150km of HVAC overhead transmission line to ensure grid stability. For HVDC connections, we assume AC-DC conversion stations are installed at the each end of the connection. For the connection between JP-E (50Hz) and JP-W (60Hz), BTB (Back-to-Back) facilities for frequency conversion are considered. Also, BTB facilities are assumed to be installed between China-Mongolia (the Gobi Desert), China-Russia and Russia-Mongolia (the Gobi Desert). Therefore, this study assumes that each economy connected via DC lines/cables or BTB for stable grid operation.

We estimated transmission costs by drawing from Bahrman & Johnson (2007), Schaber et al. (2012) and Matsuo, et al. (2015). We assume substation/switching station costs of 240M USD/station and AC-DC conversion station costs of 480M USD/station, all for stations of 3GW of transmission capacity. We also assume 1.2M USD/km for overhead lines (rated power: 3GW) and 7.2M USD/km for HVDC submarine cables (rated power: 3GW). Assumed transmission distances are shown in Figure 41. The linear programming model requires that interconnection capacity costs be expressed as cost per unit of capacity[14]. We thus calculated the initial cost for each transmission route [USD/kW], as shown in Table 15. Assumed lifetime, transmission losses and annual fixed O&M cost are 40 years, 5%/1000km and 0.3% in a ratio to initial cost, respectively (Bahrman & Johnson, 2007; Matsuo, et al., 2015).

No capacity additions are allowed in the *Base* scenario (see Section 4.2), and we do not constrain capacity additions in the other scenarios. Instead, the constraint on the net imports to each city node (equation (A.26) in Appendix A.1) indirectly regulates the maximum transmission capacity level.

Table 15 Initial cost assumptions for each interconnection route [USD/kW]

	CH-N	CH-NE	JP-H	JP-E	JP-W	KR	RU-FE	RU-SI	RU-SK	GD
CH-N	-	700	-	-	-	1 992	-	-	-	1 000
CH-NE	700	-	-	-	-	-	1 520	-	-	1 416
JP-H	-	-	-	1 392	-	-	-	-	1 288	-
JP-E	-	-	1 392	-	672	-	-	-	-	-
JP-W	-	-	-	672	-	1 840	-	-	-	-
KR	1 992	-	-	-	1 840	-	1 560	-	-	-
RU-FE	-	1 520	-	-	-	1 560	-	-	1 548	3 060
RU-SI	-	-	-	-	-	-	-	-	-	1 252
RU-SK	-	-	1 288	-	-	-	1 548	-	-	-
GD	1 000	1 416	-	-	-	-	3 060	1 252	-	-

Source: APERC analysis.
Note: '-' indicates that new interconnections are not allowed in this study.

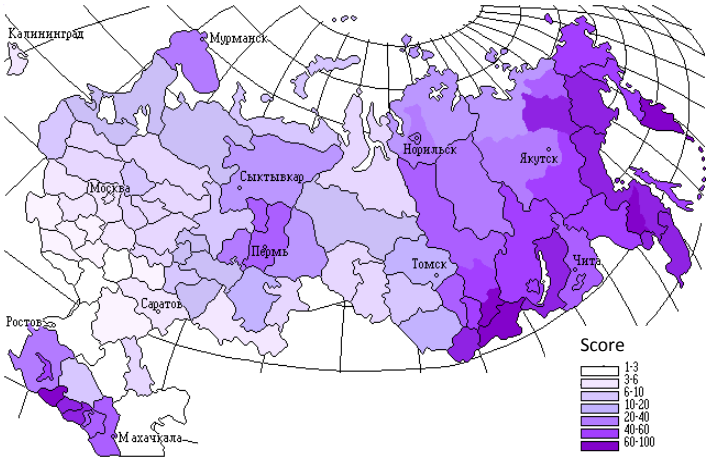
4.3.4. ADDITIONAL HYDRO POWER POTENTIAL IN RUSSIA

The assumptions for the additional hydro potential in Russia are based on estimates by the European Bank for Reconstruction and Development (from IEA (2003)). According to IEA (2003), 'economically feasible hydropower capability' in East Siberia and in the Far East is 350TWh/year and 294TWh/year, respectively. These regions

[14] Thus, the LP model does not explicitly consider the number of transmission units nor the size of each unit. In order to explicitly take into account the scale of initial investments for each unit of transmission technology, it should be considered as a future work to develop an integer programming model.

account for 81% of the total potential in Russia. However, as shown in Figure 47, hydro resources are widely distributed in the Far East region, which consists of the Far East (or federal) power grid area, the autonomous power grid area and the non-electrified area (IEA, 2003). Similarly, hydro potential in East Siberia is widely distributed from the south border region to the northern part of the region. Only limited parts of the Far East and East Siberia regions have been connected to federal grid (Popel, 2012). Therefore, we made a simple assumption that one third of the economical hydro potential of the Far East and Siberia is accessible in practice.

Figure 47 Geographical distributions of hydro energy resources, Russia



Source: Practical Science (2014).

We estimated additional hydro potential on a gigawatt-basis using the assumed 'accessible potential' (on a terawatt-hours basis), capacity factor (40%) and subtracting-off existing capacity (already exploited resources). We equally divided the total additional potential into two categories (Add-Hydro1, Add-Hydro2) as summarised in Table 16. The initial costs of hydro power potential depend on its geographical location, and in general, undeveloped resources are more expensive than already exploited resources. Thus, this study assumes a higher initial cost for the additional hydro resources compared to the already exploited resources. Add-Hyd1 is assumed to be more expensive than the average cost of already exploited resources (Table 10) by 25% and Add-Hyd2 is assumed to be more expensive by 50%.

Table 16 Assumptions for additional hydro power plants

	Additional hydro potential [GW]		Initial cost
	RU-FE	RU-SI	[USD/kW]
Additional hydro 1 (Add-hyd 1)	13	5	3125
Additional hydro 2 (Add-hyd 2)	13	5	3750

Source: APERC analysis.
Note: average cost in Russian hydro power plants is assumed as 2500 USD/kW.

However, it is important to note again that initial investments for hydro power plants differ greatly site by site and this uncertainty could affect the results presented in the Section 4.4.1 ~ 4.4.5. This study, thus, performs an additional analysis considering different sets of cost assumptions, including initial costs of hydro generation in Russia, in Section 4.4.6.

4.3.5. RESERVE MARGIN

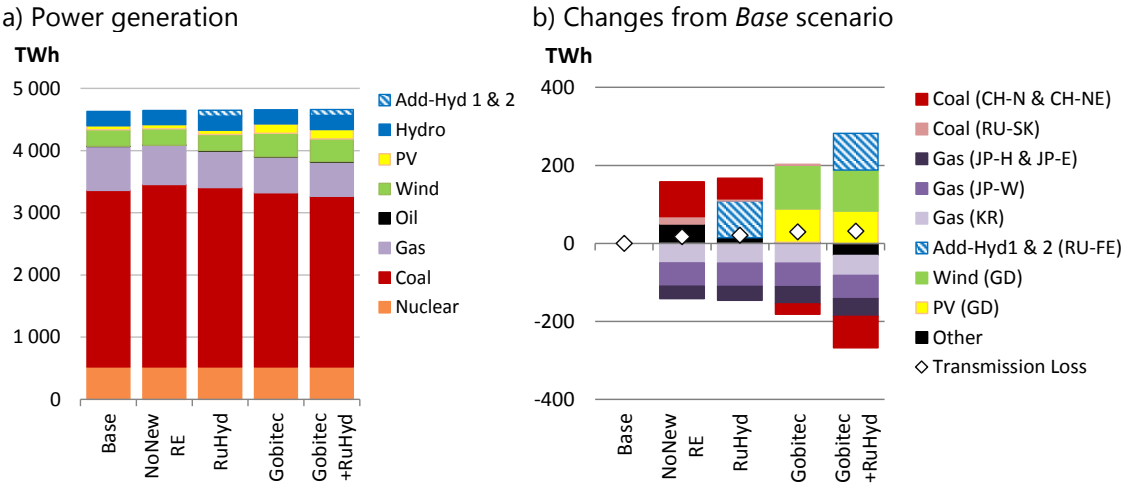
As our study focuses on hourly dispatch, we assumed operating reserve margins in equation (A.22) in Appendix A.1 as follows: 10% for China, Japan and Korea and 15% for Russia referring to general criteria and/or historical data (FEPC (2014b) for Japan, KPX (2015) for Korea and SO UPS (2014b) for Russia. As for the China nodes, we assumed a level similar to Japan and Korea, due to limited data availability).

4.4. SIMULATION RESULTS

4.4.1. GENERATION

Coal-fired generation remains the dominant source in this region even under the *Gobitec+RuHyd* scenario (Figure 48a)). In the Base scenario, coal-fired electricity accounts for 61% of total generation, and it increases to 63% in the *NoNewRE* scenario. This is because grid interconnection allows high electricity cost regions (like Japan and Korea) to access cheaper coal electricity from China and Russia. The *NoNewRE* scenario in Figure 48b) shows coal-fired generation in the China nodes and Russia Sakhalin (RU-SK) replace gas-fired generation in Japan (JP-H, JP-E and JP-W) and Korea (KR). This result implies that cost optimal grid interconnections without newly expanding renewable energy potentially increases coal-fired generation in China and Russia. This situation might be undesirable especially for China, which is suffering from severe air pollution.

Figure 48 Power generation in Northeast Asia and changes from *Base* scenario



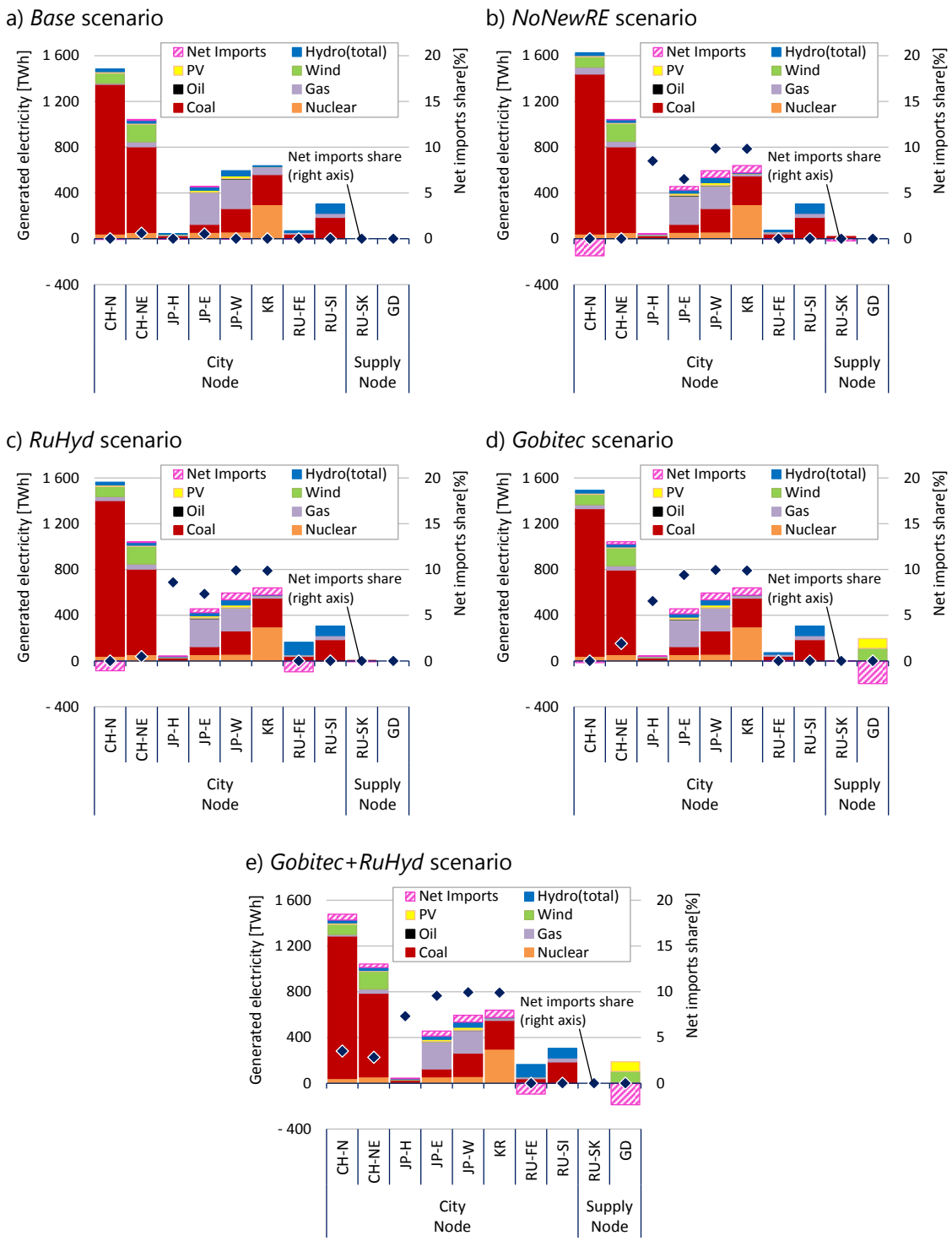
Note: PV = photovoltaic; Add-Hyd1 & 2= additional hydro-1 and additional hydro-2.

Deployments of renewables in Eastern Russia and the Gobi Desert contribute to an environmentally-friendly generation mix in NEA (Figure 48a)). Renewables account for 12% of power generation both in the *Base* and the *NoNewRE* scenario, and increase to 14%, 16% and 18% in the last three scenarios, respectively. In the *RuHyd* scenario, additional hydro generation in Eastern Russia, instead of coal-fired generation in CH-N, replaces gas-fired generation in JP-W and KR (Figure 48b)). Yet, China still exports coal-fired generation as Japan and Korea have room for further imports. In the last two scenarios, gas-fired generation in Japan and Korea as well as coal-fired generation in CH-N are replaced by renewable electricity from GD (the Gobi Desert) or Eastern Russia. The gap between the incremental generation and the generation decreases elsewhere represent cross-boundary transmission losses. Relatively large share of transmitted electricity is lost through long distance transmission; for example, transmission losses reach 15% and 11% in the last two scenarios, respectively.

Electricity trade is very limited in the *Base* scenario, and, in the *NoNewRE* scenario, net imports increases in Japan nodes and Korea node (Figure 49). The share of net imports in JP-H (Japan Hokkaido area) and JP-E (the eastern parts of Japan) reaches to 8.5% and 6.5% of annual demand, respectively. These regions import from the newly installed fossil fuel fired coal plants in Sakhalin (RU-SK) with a capacity of 3GW. JP-E also imports from China via KR and JP-W as well (see also Section 4.4.3). As noted in Section 2.2, the model limits net transmission inflows to each city node to the reserve margin at all times, reflecting a likely concern over secure electricity supply (see Equation (A.26) in Appendix A.1). These reserve margins are assumed to be 10% for China, Japan and Korea and 15% for Russia. In JP-W and KR, the net imports almost reach this upper bound on average. The main exporter to these nodes is China (see also Section 4.4.3).

In the *RuHyd* scenario, large scale hydro developments in RU-FE allow KR, JP-W and JP-E to import the hydroelectricity from Russia instead of fossil fuel-fired electricity from China or Russia. The net imports share in these importing nodes remains similar in level to the *NoNewRE* scenario; Japan and Korea nodes remains as the main importers. The 'Gobi electricity' in the *Gobitec* scenario increases the imports share in CH-NE to 1.9%, which contributes to reducing coal-fired generation in the China. In the *Gobitec+RuHyd* scenario, the annual imports of the two China nodes amount 82TWh/y (net imports share: 4% in CH-N and 3% in CH-NE), resulting in further reductions of coal generation in China (see also Figure 48b)). Our model calculates electricity flow based on cost-optimisation; therefore, higher cost electricity is replaced first by cheaper transmitted electricity. China starts large-scale imports in the last scenario as the net imports share almost reaches the upper bound level in higher cost nodes (not only JP-W and KR but also JP-E). This result implies that, from the economic standpoints, massive deployments of renewables both in NEA are necessarily to largely reduce cheap but carbon-intensive coal generation in China.

Figure 49 Power-generation mix and net imports by node

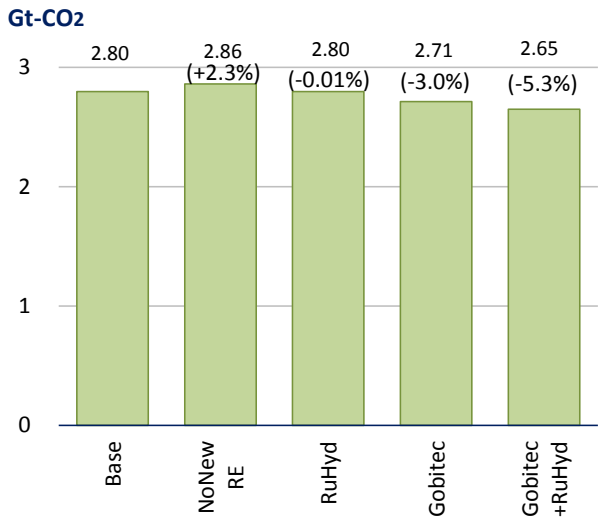


Note: PV = photovoltaic. Note: 'Net Imports' in the figures indicates 'Net Imported Electricity' for a positive value and 'Net Exported Electricity' for a negative value. 'Hydro (total)' indicates a sum of 'Hydro', 'Additional hydro-1' and 'Additional hydro-2'.

4.4.2. CO_2 EMISSIONS

Figure 50 displays direct CO_2 emissions in NEA from fossil fuel combustion. Larger coal-fired generation in the *NoNewRE* scenario results in higher emissions by 64Mt-CO_2 (+2.3%) compared to the *Base* scenario. This result implies that interconnection without renewable resource expansion could increase CO_2 emissions in NEA, which is not desirable from the environmental perspectives. In the *RuHyd* scenario, additional hydro developments in Eastern Russia slightly reduce the emissions by 0.4Mt-CO_2 (-0.01%). In the *Gobitec* and *Gobitec+RuHyd* scenarios, Gobi electricity or Gobi electricity + hydro in Eastern Russia contribute to emissions reductions of about 84Mt-CO_2 (-3.0%) and 149Mt-CO_2 (-5.3%), respectively. These last two scenarios result in larger reductions as the massive renewable deployments replace carbon-intensive coal-fired electricity in China (see Figure 48b)). The modest benefit to emissions in the *RuHyd* scenario is because the emissions from exported coal-fired generation in China (Figure 48b)) partly offset the reductions from hydro in Russia.

Figure 50 Direct CO_2 emissions, Northeast Asia



Source: APERC analysis.

The CO_2 reduction in the *Gobitec* scenario that we calculate (84Mt-CO_2) is lower than that from Energy Charter, et al. (2014) (187Mt-CO_2). (Please note that Energy Charter et al. (2014) mentioned a 187Gt-CO_2 reduction, but we suspect the units were misstated.) The CO_2 reduction differences are partly because of two factors. First, in Energy Charter, et al. (2014), the assumptions for utilization factor for both PV and wind are 30%, which are much higher than our estimates (20% for PV and 26% for wind). Second, the two models use a substantially different dispatch logic for Gobi electricity. Energy Charter, et al. (2014) assumed that 80% of Gobi electricity is sent to coal-intensive (high CO_2 emissions per kWh) China, and they use average emissions factors in each importing region to estimate CO_2 emission reductions. On the other hand, our model determines the share of Gobi electricity at each importing node

based on total system cost minimization. Thus, as shown in Figure 48b), the increase in Gobi electricity results in reducing high cost gas-fired generation (with relatively low CO_2 emissions per kWh) in Japan and Korea.

4.4.3. ELECTRICITY FLOW

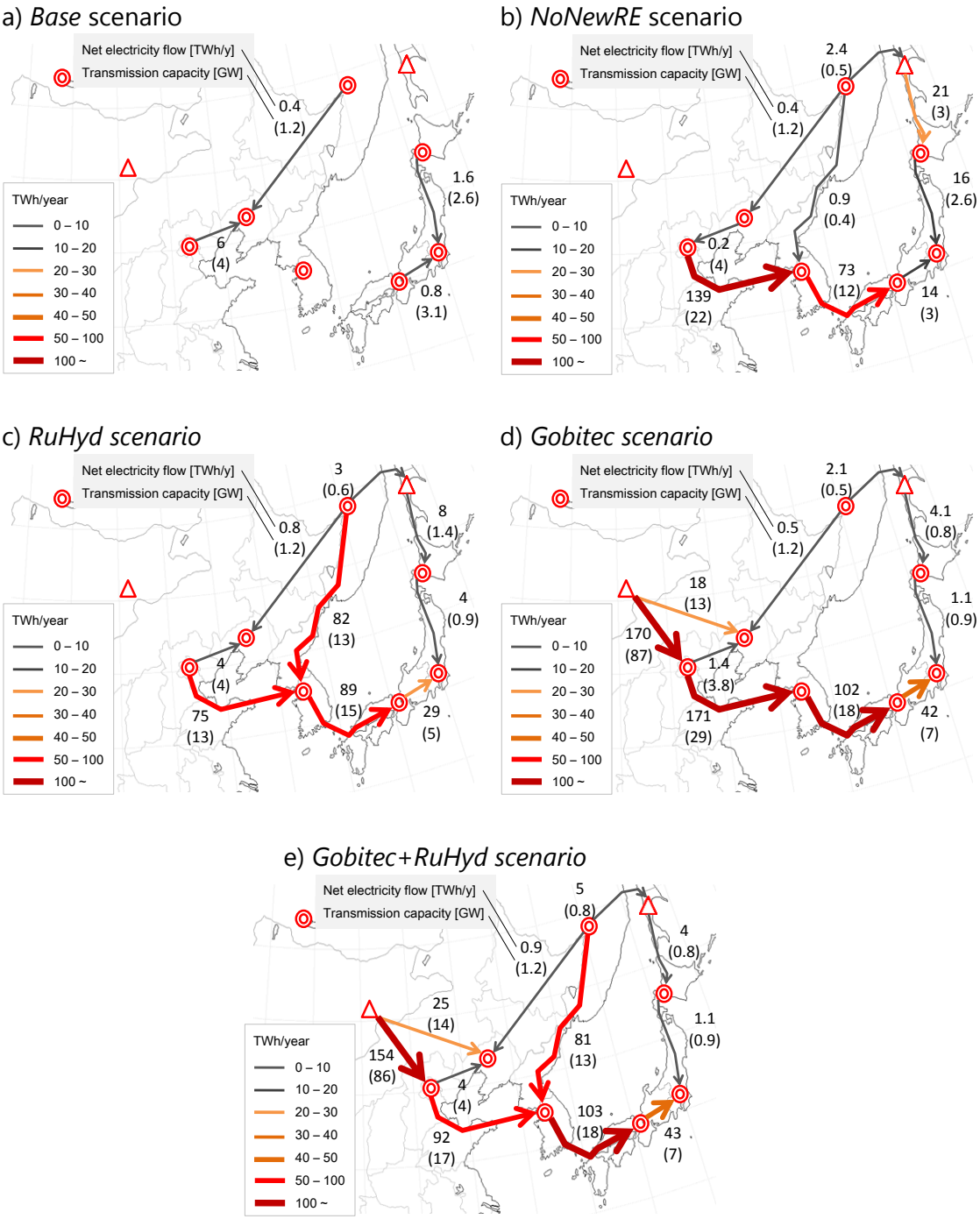
Figure 51a)-e) indicates cross-boundary electricity flows [terawatt-hours/year (TWh/y)] and transmission capacity [Gigawatt (GW)]. The *Base* scenario shows an international power trade only between Russia Far East (RU-FE) and Northeast China (CH-NE).

In the *NoNewRE* scenario, China and Russia export to Japan and Korea because of low-cost electricity. Korea becomes a net importing economy as well as playing the role of a transit ("bridge") economy between China/Russia and Japan. The economy imports 139TWh/y from China, and exports to 73TWh/y to Japan. Transmission line capacity of the China-Korea and Korea-Japan interconnections are 22GW and 12GW, respectively, which are equivalent to 18% and 10% to the total installed capacity of Korea. The figure also shows the newly added interconnections from Russia Sakhalin to the eastern parts of Japan via Hokkaido (JP-H); however, the transmission capacity from the 'mainland' Russia Far East region (RU-FE) to Japan and Korea is relatively small compared to the aforementioned connections. The limited transmission scale is probably because of the higher transmission cost associated with the longer transmission distances.

On the other hand, in the *RuHyd* scenario, RU-FE becomes a major exporter to Japan and Korea. The majority of the additional hydroelectricity in RU-FE is transmitted to KR (82TWh/y). The *Gobitec* scenario shows the large-scale cross-border electricity flow from the Gobi Desert area to Korea and Japan. Transmission lines with a capacity of 100GW are installed from GD (the Gobi Desert) to match the capacity of the variable renewables there. Yet the utilization rate of these connections, i.e., 22% in the GD~CH-N connection, is relatively low because of the intermittency of the transmitted power. In the *Gobitec+RuHyd* scenario, transmitted electricity from China to Korea decreases compared to the *Gobitec* scenario because Korea imports power from Russia rather than China. Instead, China consumes more of the Gobi Desert electricity, resulting in lower fossil fuel-fired generation in the China nodes.

Electric utilities and transmission companies in Russia, in cooperation with organizations in neighbouring economies, have been exploring the possibilities of cross-border grid interconnection (Smirnov, 2012; Inter RAO, 2013). Our results indicate that exporting fossil fuel-fired electricity from Sakhalin to Japan could be an economic option. By contrast, the scale of connections from Eastern Russia is relatively small in the *NoNewRE* and *Gobitec* scenarios, and it greatly expands under the *RuHyd* and *Gobitec+RuHyd* scenarios in order to export additional hydro power. The results imply that additional hydro power can stimulate opportunities for electricity trade between the 'mainland' Russia and other regions.

Figure 51 Annual electricity flows, each scenario, Northeast Asia



Source: APERC analysis.

4.4.4. TOTAL COSTS AND INVESTMENTS

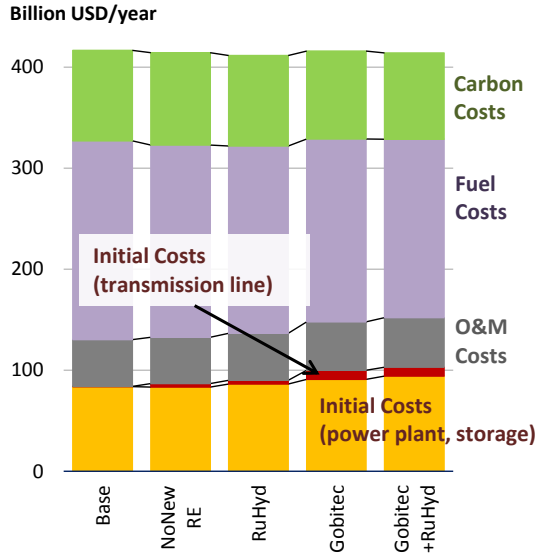
Figure 52 depicts yearly total system cost and its changes from the *Base* scenario. The costs shown include a carbon cost of 30 USD/t-CO_2 (see Table 8). The total system cost declines by 2.3B USD/y, 5.1B USD/y, 0.7B USD/y, and 2.7B USD/y from the *Base* in the *NoNewRE*, *RuHyd*, *Gobitec*, and *Gobitec+RuHyd* scenarios, respectively. These

values are equivalent to 0.2%~1.2% reductions; therefore, the impacts of interconnection on total system cost appear to be modest in this analysis. The annualized share of initial cost of cross-boundary transmission to total system cost is relatively small, e.g., 2.2% in the *Gobitec+RuHyd* scenario.

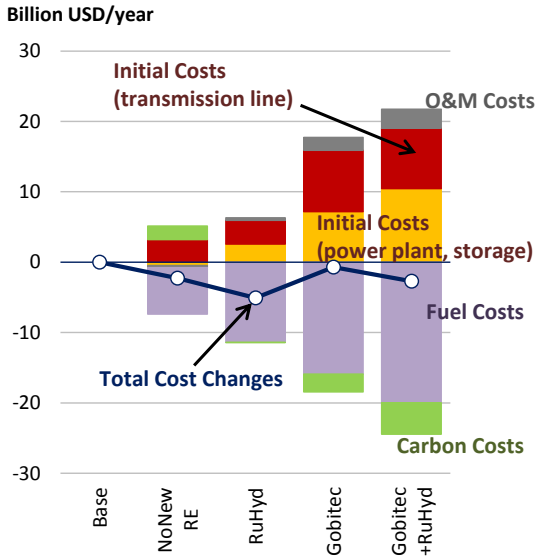
However, grid interconnection affects some components of the total system cost more significantly. As shown in the last three scenarios in Figure 52b), while deployment of renewables in Gobi and Eastern Russia and transmission lines have significant initial costs, renewable resource expansion contributes to fuel cost reductions in the NEA region of about 6% (-11B USD/y), 8% (-16B USD/y) and 10% (-20B USD/y) in the last three scenarios, respectively. These results imply two points as follows: first, the benefits of renewable electricity trade mainly depend on fuel cost reductions; second, the main costs which make the power trade and renewable expansion less attractive are the initial costs of renewables and transmission lines.

Figure 52 Yearly total system costs and changes from *Base* scenario, Northeast Asia

a) Yearly system costs



b) Changes from *Base* scenario

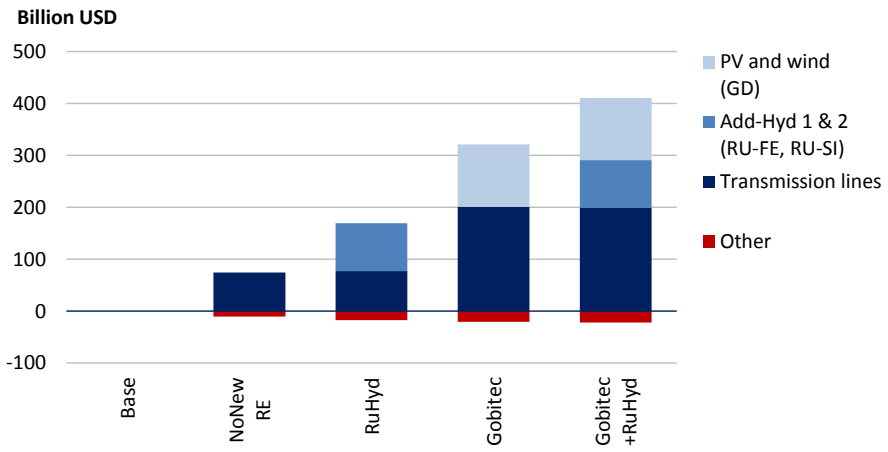


Source: APERC analysis.
Note: O&M = Operation and Maintenance.

Large fuel cost savings are estimated in the importing regions, especially in the last scenario: 3B USD/y, 11B USD/y and 6B USD/y in the China nodes, Japan and Korea, respectively, which are equivalent to 4%, 15% and 23% reductions. Nevertheless, these results rely on the future cost assumptions in Section 4.3.2. In order to investigate the impact of future cost uncertainties on the economics of grid interconnection, we perform a sensitivity analysis on the assumptions for fuel cost and the initial cost of transmission lines and renewable energy in Section 4.4.6.

Huge investments are necessary for grid interconnection and massive deployments of renewables (Figure 53). Compared to the *Base* scenario, additional investments amount 60B USD, 150B USD, 300B USD and 390B USD in the *NoNewRE* ~ *Gobitec+RuHyd* scenario, respectively. Estimated yearly total costs of Japan plus Korea (*Base* scenario) is approximately 190B USD/year; therefore, the total investments in the *Gobitec+RuHyd* scenario are more than doubled yearly costs of the two economies. As mentioned above, economic benefits in the form of cost reductions appear to be modest. Given the large scale investments are required for the concept, the NEA-wide interconnections may face an implementation challenges due to financing issues (i.e., who can and how to finance). Our analysis of course includes simplifications especially in terms of temporal and geographical resolution. The relevant organisations should examine the return on investments in a more detailed manner (i.e., assessment of specific interconnection routes considering local power grid characteristics) before implementation.

Figure 53 Additional investments from *Base* scenario, Northeast Asia

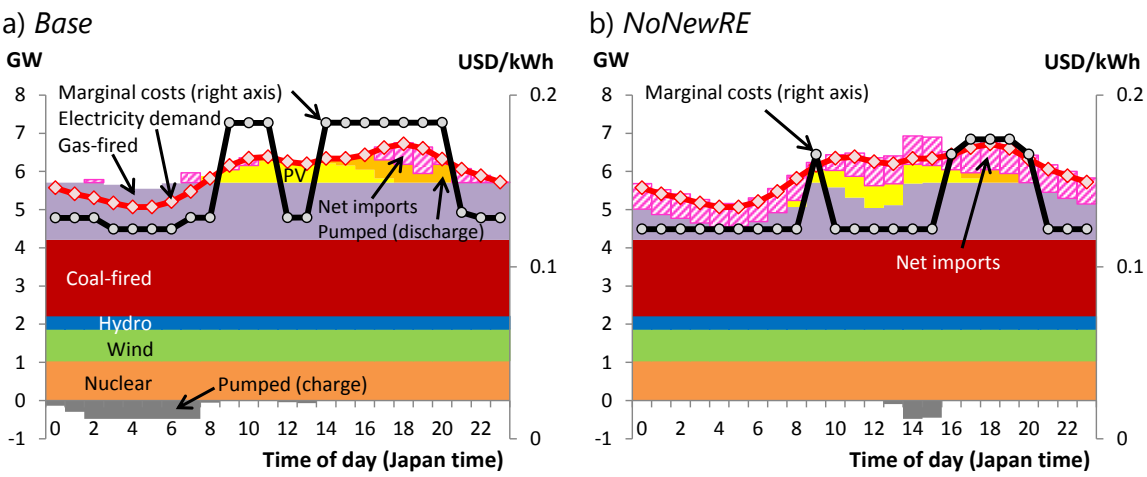


Source: APERC analysis.

4.4.5. MARGINAL GENERATION COSTS

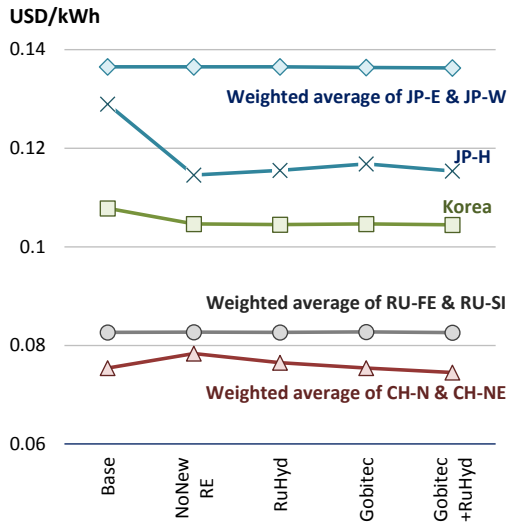
The dual solution to equation (A.7) in Appendix A.1 indicates the marginal costs of electricity generation, which are determined by the variable cost of generation, storage, and transmission. The marginal costs are important indicators of the electricity price level (IES, 2004; Schaber, et al., 2012). Figure 54 shows the power generation profile and marginal generation costs in the winter peak season in JP-H in the *Base* and *NoNewRE* scenarios as an example. A comparison of the two figures indicates that power imports reduce gas-fired generation and contribute to a lowering of marginal costs, especially during daytime (around 9:00~11:00 and 13:00 ~20:00). For example, at around 14:00, the marginal costs drop from 0.18 USD/kWh in the *Base* scenario to 0.12 USD/kWh in the *NoNewRE* scenario.

Figure 54 Power-generation profile and marginal generation costs, winter season, Japan Hokkaido node (JP-H)



Source: APERC analysis.

Figure 55 Average marginal generation costs

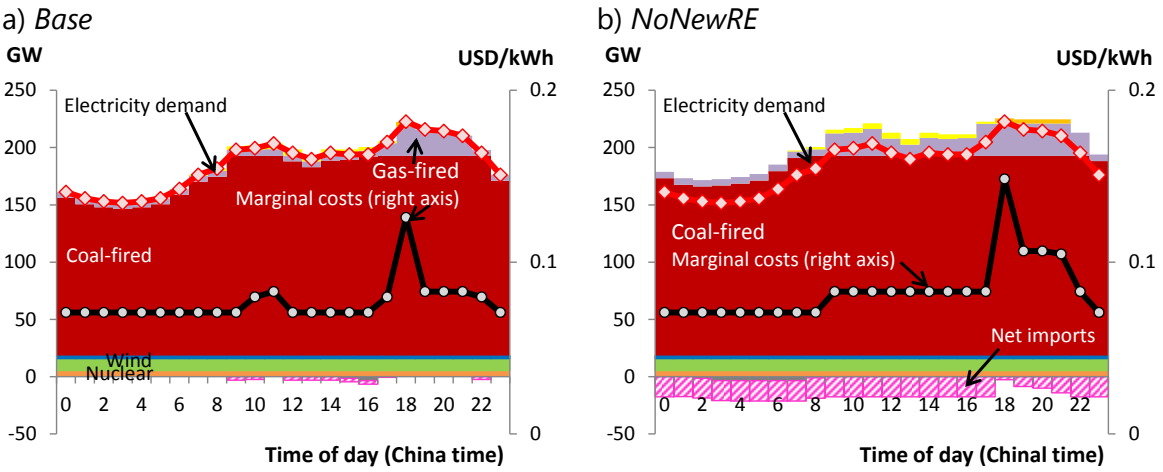


Source: APERC analysis.

Figure 55 presents the average marginal generation costs in the city nodes for the five scenarios. For the China nodes and the Japan nodes (except JP-H), the figure shows weighted average values. The average marginal costs varies from economy to economy in NEA; it ranges from 0.075 USD/kWh in the China nodes to 0.107 USD/kWh in Korea and 0.137 USD/kWh in Japan (except JP-H) in the *Base* scenario. Our model dispatches generation with the lowest variable cost first; therefore, marginal generation cost

increases with larger electricity demand. As grid integration decreases net-demand[15] of importing regions, the average marginal costs lowers in in electricity importing regions (and *vice versa*. See CH-N in the *NoNewRE* scenario in Figure 55 and marginal costs from 11:00~21:00 in Figure 56). The Japan Hokkaido area (JP-H) and Korea (KR) show relatively large reductions as the power imports significantly decrease or almost replace high-marginal cost generation, such as oil-fired and gas-fired generation, as shown in Figure 49 and Figure 54. In the *NoNewRE*, the average marginal costs drops by 0.014 USD/kWh in JP-H and by 0.003 USD/kWh in Korea, which are equivalent to 11% and 3% reductions, respectively. As for the last three scenarios, the average marginal costs in both regions remain at a similar level to the *NoNewRE* scenario.

Figure 56 Power-generation profile and marginal generation costs, winter peak season, China North node (CH-N)

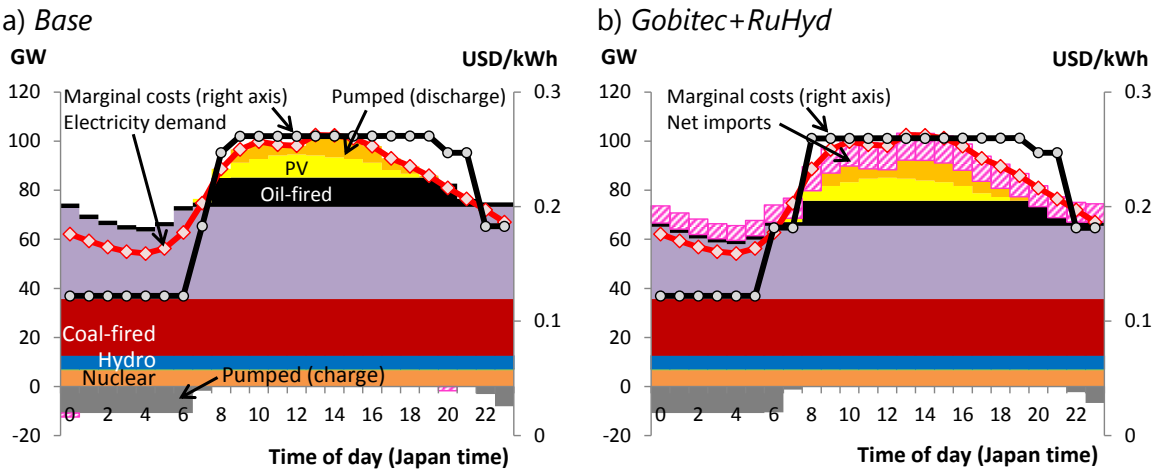


Source: APERC analysis.

The Japan nodes, except JP-H, show small changes in average marginal generation costs as the share of high marginal cost generation is relatively large compared to JP-H, and the limited imports (which must be kept less than the reserve margin) are not enough to eliminate them (see Figure 57). After the nuclear power plant accident in Japan, electric utilities across the economy raised residential electricity prices by 13~37% (from March 2011 to July 2014) primarily because of additional fuel costs (NHK, 2014), and proposals for grid interconnection received increasing attention in Japan as one of the potentially effective measures for lowering prices. Our results indicate that parts of Japan would locally enjoy lowered prices from grid interconnections. Yet, in Japan as a whole, even with the accelerated renewable developments, the price reductions would be relatively small compared to the increases after the nuclear accident, at least as long as imports are constrained due to energy security concerns.

[15] Domestic demand minus net imports.

Figure 57 Power-generation profile and marginal generation costs, summer peak season, Japan West node (JP-W)



Source: APERC analysis.

4.4.6. SENSITIVITY ANALYSIS

Figure 52b) suggested that the benefits achieved by interconnecting power grids and promoting trade in renewable electricity depend mainly on fuel cost savings, and that higher initial cost of renewables and transmission lines makes regional interconnections less attractive. Also, uncertainties exist in future environmental policies and regulations, including carbon prices. Therefore, in this section, we conduct a sensitivity analysis on these three factors to investigate their impacts on the economics of grid interconnection. We calculated one hundred-fifty cases total as shown in Table 17: **two installed capacity settings** (generation, storage and transmission capacity are fixed to the *Base* or *Gobitec+RuHyd* scenario result) × **three carbon prices** (No carbon price, 30USD/t-CO_2 (="*Ref.*"), 100USD/t-CO_2) × **five fossil fuel prices** (-20%, -10%, 0% (="*Ref.*"), +10%, +20% from Table 14) × **five initial costs** of renewable energy in the Gobi Desert and Russia and all transmission lines (-20%, -10%, 0% (="*Ref.*"), +10%, +20%). Other assumptions are the same as shown in Table 9 ~ Table 13.

Figure 58 illustrates the economic benefits of the *Gobi+RuHyd* scenario in each case (total system cost reductions from the *Base*). The results show improved economic viability of grid interconnections under lower initial cost, higher fossil fuel prices or higher carbon prices. For example, the benefit increases to 12B USD/y in the +20% fossil fuel price and -20% initial cost case under 30USD/t-CO_2 carbon price (this benefit is approximately equivalent to a 3% total cost saving). Also, the benefit expands to 24B USD/y with a carbon price of 100USD/t-CO_2. On the other hand, the results also suggest the benefit would shrink or become negative with 10~20% lower fuel prices and higher initial costs under 30USD/t-CO_2. In 'no carbon price' case, economic benefits become negative (-2B USD/y) even under the reference fuel prices and initial costs.

Table 17 Case settings of sensitivity analysis (150 cases total)

Case settings	
Installed capacity settings of generation, storage and transmission facilities	Fixed to the *Base* or *Gobitec+RuHyd* scenario result
Carbon prices	No carbon price, 30USD/t-CO_2, 100USD/t-CO_2
Initial cost changes for renewables (the Gobi Desert and Russia) and transmission lines	-20%, -10%, 0% (='*Ref.*'), +10%, +20%
Fossil fuel price changes from Table 14	-20%, -10%, 0% (='*Ref.*'), +10%, +20%

Source: APERC analysis.

Figure 58 Economic benefits of the *Gobi+RuHyd* scenario in each case

a) No carbon price

Unit: Billion USD/year

Fossil fuel prices \ Initial costs	-20%	-10%	Ref.	+10%	+20%
+20%	7	5	2	0	-2
+10%	5	3	0	-2	-4
Ref.	3	1	-2	-4	-6
-10%	1	-1	-4	-6	-8
-20%	-1	-3	-6	-8	-10

Initial costs (renewables in Gobi and Russia and transmission lines)

b) 30USD/t-CO_2 ('*Ref*')

Unit: Billion USD/year

Fossil fuel prices \ Initial costs	-20%	-10%	Ref.	+10%	+20%
+20%	12	9	7	4	2
+10%	10	7	5	2	0
Ref.	8	5	3	0	-2
-10%	6	3	1	-2	-4
-20%	4	1	-1	-4	-6

Initial costs (renewables in Gobi and Russia and transmission lines)

c) 100USD/t-CO_2

Unit: Billion USD/year

Fossil fuel prices \ Initial costs	-20%	-10%	Ref.	+10%	+20%
+20%	22	20	17	15	12
+10%	20	18	16	13	11
Ref.	19	16	14	11	9
-10%	17	15	12	10	7
-20%	15	13	11	8	6

Initial costs (renewables in Gobi and Russia and transmission lines)

Source: APERC analysis.

In Section 4.4.1 ~ 4.4.5, we assumed estimated initial costs of renewables and transmission lines in 2030 based on IEA (2014a), Bahrman & Johnson (2007) and so on. However, these costs, especially for hydro generation and transmission lines, depend on site-specific characteristics. Also, IEA (2014a) assumes learning rates which reduce the future initial costs of renewables, yet uncertainties exist in these cost reduction trends. Similarly, energy prices have shown their volatile nature in the past decade, and the NEA region does not have a regional carbon market nor carbon reduction regulations. The relevant planning organizations should carefully assess the actual initial costs and long-term fossil fuel price trends, bearing in mind their significance, as indicated Figure 58. In addition, given the benefits expand under higher carbon prices, Regional carbon market and emission reduction agreements are important for implementing power grid interconnections.

5.CONCLUSIONS AND POLICY IMPLICATIONS

This research report summarises overview of the power grids and grid interconnection proposals in major NEA economies (Section 2 and 3), where we highlighted the need for coordination by international/regional organisations for a detailed blueprint and for effective implementations. Section 4 is the main content of this study: a quantitative assessment of the economic viability of grid interconnections in NEA and renewable energy developments in the Gobi Desert and Eastern Russia.

In Section 4, we develop a single-year multi-region power system model. The model is formulated as a linear program, which aims to minimize overall system cost. The model considers nodal electric load characteristics, including representative hourly load curves, as well as the output profile of variable renewables in the Gobi Desert. We validated our model capability using historical data (see Appendix A.2).

We investigated five scenarios for the NEA power system of 2030: *Base*, *NoNewRE*, *RuHyd*, *Gobitec* and *Gobitec+RuHyd* scenarios (see Table 8). Major results in each scenario are summarized in Table 18. These simulation results lead us to several interesting findings as follows.

Table 18 Summary of the simulation results of each scenario

Scenario	*Base*	*NoNewRE*	*RuHyd*	*Gobitec*	*Gobitec +RuHyd*
Annual total cost	417B USD/y	414B USD/y	412B USD/y	416B USD/y	414B USD/y
Initial costs	84B USD/y	87B USD/y	90B USD/y	100B USD/y	103B USD/y
Fuel costs	197B USD/y	190B USD/y	185B USD/y	181B USD/y	177B USD/y
Annual CO_2 emissions	2.80 Gt-CO_2	2.86 Gt-CO_2	2.80 Gt-CO_2	2.71 Gt-CO_2	2.65 Gt-CO_2
Share of coal-fired generation in NEA	61%	63%	62%	60%	59%
Share of renewables in NEA	12%	12%	14%	16%	18%

Source: APERC analysis.
Note: Due to different model setups, the results in this report are slightly different from the author's journal article: '*Electric Power Interconnections in Northeast Asia: a Quantitative Analysis of Opportunities and Challenges', Takashi Otsuki, Aishah B. Mohd Isa and Ralph D. Samuelson, Energy Policy (accepted, in press)*. For example, this report considers the Russia-Siberia node as a city node (Figure 41), while the journal article considers it as a supply node.

First, from an environmental perspective, the *Gobitec+RuHyd* scenario shows that access to wind/solar resources in the Gobi Desert and additional hydro resources in Eastern Russia promotes an environmentally-friendly generation mix. The total

renewable share in NEA increases from 12% to 18% of which 2% is from Russia and the remaining 4% is from the Gobi Desert. Deployment of these renewables contributes to NEA emission reductions of 5.3%. By contrast, the *NoNewRE* scenario shows that cost-optimal grid interconnections without renewable energy development would promote low-cost coal generation in China and Russia, resulting in an increase CO_2 emissions in NEA (+2.3% from the *Base*) and potentially worse air pollution in China. Thus, interconnection projects should be undertaken in tandem with renewable energy expansion in order to reap both economic and environmental benefits.

Second, all grid interconnection scenarios indicate that economic benefits in the form of total cost reductions depend mainly on the fuel cost saved by shifting to cheaper fossil fuel or to renewables. Expanding renewable energy results in larger fuel cost savings, for example the 3% reductions (-7B USD/y) in the *NoNewRE* versus the 10% reductions (-20B USD/y) in the *Gobitec+RuHyd*. However, the total system cost reductions appear modest (less than 1.2% reduction from the *Base*) due to the increase in initial costs and O&M costs. In addition, sensitivity analysis on fuel prices and initial costs (Section 4.4.6) imply that the benefit potentially shrinks or becomes negative with 10%~20% lower fuel prices and higher initial costs. These limited economic benefits are likely to be a major challenge to implementing grid interconnection in NEA. Given the large scale investments are required for NEA-wide interconnections (Section 4.4.4), the relevant planning organizations should carefully assess the actual initial costs and long-term fossil fuel price trends in order to assure that implementation will be beneficial. Section 4.4.6 also shows that carbon prices are important for profitable implementation. The relevant organisations or economies need to work on the establishment of regional carbon market and regional emission reduction agreements.

Third, the *RuHyd* and *Gobitec+RuHyd* results imply that interconnection opportunities between 'mainland' Russia (Siberia and Far East) and the rest of NEA expand with additional hydro development in Eastern Russia. Hence, access to additional hydropower will be the driver of opportunities for grid interconnections between Russia and other regions.

Turning to priorities for future work, Section 4.4.6 mentioned the importance of site-specific characteristics to the cost of renewables and transmission lines. Further examination of site-specific costs, as well as site-specific performance of renewables, should be undertaken. For example, if detailed meteorological data were available in each node (i.e., hourly or more detailed data for a full year), future work could better characterize the output of intermittent renewables.

Future work should perform sensitivity analysis on the upper bounds for net imports in importing regions and the installed capacity of renewables in the Gobi Desert. Also, additional modelling of other types of renewables, including biomass in China, would be interesting to discuss their contribution to emissions reductions in NEA region. Future work might discuss the mechanisms to appropriately share the cost-burden and the credit for emission reductions among the NEA regions.

Our modelling approach includes some simplifications that should be addressed in future work. The single-year simulation could be replaced with a multi-year simulation in order to examine the evolution of costs and benefits over time. Perhaps most importantly, the current model is deterministic in nature. Incorporating probabilistic representations could improve the robustness of the model in at least two ways. First, incorporating probabilistic behaviour into the representation of intermittent renewables would allow a more detailed examination of NEA-wide grid integration issues, not only for the Gobi Desert renewables discussed in this paper, but also for intermittent renewables in the other NEA economies. Second, a probabilistic representation of the performance of additional system components (transmission lines and thermal generating facilities) would allow the model to address the impact of NEA grid interconnection on power system reliability and the costs of maintaining reliability.

APPENDIX

A.1 MATHEMATICAL FORMULATION

We describe the equations of the model in order to provide a detailed understanding of this study. Table A1 shows endogenous variables of the model.

Table A1 Endogenous variables in the multi region power system model

Endogenous variables
TC: Total annual cost [USD]
$xp_{n,p,s,t}$: Output of power plant *p* at local time *t* in season *s* in node *n* [kW]
$de_{n,p,s,t}$: Suppressed output of power plant *p* (*p*=wind or PV) at local time *t* in season *s* in node *n* [kW]
$mp_{n,p,s}$: Daily maximum output of power plant *p* in season *s* in node *n* [kW]
$kp_{n,p}$: Capacity of power plant *p* in node *n* [kW]
$xl_{n,n2,s,t}$: Power exports from node *n* to node *n2* via line type *l* at time *t* (node *n* time) in season *s* [kW]
$kl_{n,n2,l}$: Total transmission capacity between node *n* and *n2* via line type *l* [kW]
$xch_{n,st,s,t}$: Electricity charge of storage *st* at local time *t* in season *s* in node *n* [kW]
$xdc_{n,st,s,t}$: Electricity discharge of storage *st* at local time *t* in season *s* in node *n* [kW]
$ste_{n,st,s,t}$: Stored electricity of storage *st* at local time *t* in season *s* in node *n* [kWh]
$kst_{n,st}$: kW-capacity of storage *st* in node *n* [kW]
where $n, n2 \in$ {1:CH-N, 2:CH-NE, 3:JP-H, 4:JP-E, 5:JP-W, 6:KR, 7:RU-FE, 8:RU-SI, 9:RU-SK, 10:GD},
$s \in$ {1:Summer-Peak, 2:Summer-Average, 3:Winter-Average, 4: Winter-Peak, 5: Intermediate }
$t \in \{0, 1, \ldots, 23\}$
$p \in$ {1:Nuclear, 2:Coal fired, 3:Gas fired, 4:Oil fired, 5:Hydro, 6: Wind, 7:PV, 8:Additional hydro 1 (Add-Hyd1), 9:Additional hydro 2 (Add-Hyd2)}
$st \in$ {Pumped Hydro Storage}
$l \in$ {HV interconnection}

Source: APERC analysis.

OBJECTIVE FUNCTION

Equation (A.1) is the objective function. This model minimizes total system cost for a single representative year. System cost is composed of annualized initial cost, O&M cost, fuel cost and carbon cost for the whole of Northeast Asia (NEA). The cost of power plant includes all four cost components above. The cost of a storage and transmission line consists of initial cost and fixed O&M cost. Therefore, the model choose cross-border power trade if its benefit (i.e., fuel cost savings) is larger than the fixed cost of transmission line.

Equation (A.2)~(A.5) describe each component. In equation (A.2), annualized initial cost of power plant, storage and transmission line are calculated as the product of a

capital recovery factor (*PA*, *STA* and *LA*, respectively), unit construction cost and installed capacity. For capital recovery factor calculation, the assumed discount rate is 3% and the lifetime assumptions are as discussed in Section 4.3.2 and 4.3.3. Equation (A.3) describes the O&M cost of power plant (fixed and variable O&M cost), storage (fixed O&M) and cross-border transmission line (fixed O&M). Equation (A.4) and (A.5) respectively describe fuel cost and carbon cost for direct emissions. Time slot length (*HW*) is calculated in equation (A.6). Assumed seasonal length (*SW*) is in Table A2, and time slice length (*TW*) is 1 hour.

$$min.TC = \sum_{n} (CI_n + CO_n + CF_n + CC_n) \tag{A.1}$$

$$CI_n = \sum_{p} PA_p \cdot PI_{n,p} \cdot kp_{n,p} + \sum_{st} STA_{st} \cdot STI_{n,st} \cdot kst_{n,st} + \sum_{n2<n} \sum_{l} LI_l \cdot LI_{n,n2,l} \cdot kl_{n,n2,l} \tag{A.2}$$

$$CO_n = \sum_{p} \left(POF_{n,p} \cdot PI_{n,p} \cdot kp_{n,p} + \sum_{s} \sum_{t} POV_{n,p} \cdot xp_{n,p,s,t} \cdot HW_{s,t} \right) + \sum_{st} STOF_{n,st} \cdot STI_{n,st} \cdot kst_{n,st} + \sum_{n2<n} \sum_{l} LOF_l \cdot LI_{n,n2,l} \cdot kl_{n,n2,l} \tag{A.3}$$

$$CF_n = \sum_{p} \sum_{s} \sum_{t} PF_{n,p} \cdot xp_{n,p,s,t} \cdot HW_{s,t} \tag{A.4}$$

$$CC_n = \sum_{p} \sum_{s} \sum_{t} CTAX \cdot Carbon_p \cdot xp_{n,p,s,t} \cdot HW_{s,t} \tag{A.5}$$

$$HW_{s,t} = 8760 \cdot SW_s \cdot TW_t / 12/24 \tag{A.6}$$

Where: $\boldsymbol{CI_n}$: annualized initial cost of power plant, storage and transmission line in node *n* [USD/year], $\boldsymbol{CO_n}$: annual O&M cost of power plant, storage and transmission line in node *n* [USD/year], $\boldsymbol{CF_n}$: annual fuel cost in node *n* [USD/year], $\boldsymbol{CC_n}$: annual carbon cost for fuel combustion [USD/year], $\boldsymbol{PA_p}$: capital recovery factor of power plant type *p*, $\boldsymbol{PI_{n,p}}$: initial cost of power plant type *p* in node *n* [USD/kW], $\boldsymbol{STA_{st}}$: capital recovery factor of storage type *st*, $\boldsymbol{STI_{n,st}}$: initial cost of storage type *st* in node *n* [USD/kW], $\boldsymbol{LA_l}$: capital recovery factor of transmission line, $\boldsymbol{LI_{n,n2,l}}$: initial cost of transmission line between node *n* and *n2* [USD/kW], $\boldsymbol{POF_{n,p}}$: fixed O&M cost rate of power plant type *p* as a fraction of the initial cost, $\boldsymbol{POV_{n,p}}$: variable O&M cost of power plant type *p* [USD/kWh], $\boldsymbol{STOF_{n,st}}$: fixed O&M cost rate of storage type *st* as a fraction of the initial cost, $\boldsymbol{LOF_l}$: fixed

O&M cost rate of a transmission line as a fraction of the initial cost, $\boldsymbol{PF_{n,p}}$: fuel cost of power plant type *p* [USD/kWh], $\boldsymbol{Carbon_p}$: carbon intensity of power plant type p [t-CO_2/kWh], ***CTAX***: carbon price [USD/t-CO_2], $\boldsymbol{HW_{s,t}}$: length of time slot at local time *t* in season *s* [hours], $\boldsymbol{SW_s}$: length of season s [Months] (see Table A2), $\boldsymbol{TW_t}$: length of time slice *t* [hour] (=1hour).

Table A2 Assumed length of each season

Season	Assumed length [Months]
Summer-peak	0.2
Summer-average	2.8
Winter-peak	0.2
Winter-average	2.8
Intermediate	6.0

Source: APERC analysis.

CONSTRAINTS

Electricity demand–supply balance

Equation (A.7) ensures that electricity demand must be satisfied at all times in all seasons and in all nodes. The left part indicates the sum of power supply from domestic generators, net power imports and net power discharge of storage facilities. Cross-boundary transmission losses are considered when transmitted power reaches the importing node by multiplying exported power by transmission efficiency (*xl*LE*). Time differences between power exporting and importing nodes are considered for imported power. *ImT* indicates the local time at the origin of electricity imports defined as below. Note that we number hours of the day from 0 to 23 (Table A1).

The dual solution to this equation indicates the marginal costs of electricity generation. The marginal costs are determined by the variable cost of generation, storage, and transmission. Losses in transmission and storage indirectly increase marginal costs and total system cost, as they lead to higher demand for power generation (Schaber, et al., 2012) Equation (A.8) shows how we calculate cross-border transmission efficiency.

This model does not explicitly consider modes of operation of generation and storage facilities. In the real world, storage facilities are either in charging mode (pumping mode for pumped hydro storage), discharging mode (generation mode) or standby mode at any given time. In our linear programming model, equation (A.7) technically allows both charging and discharging simultaneously. However, because of the power losses this would involve, as represented in equation (A.23)~(A.24) below, the model will avoid a solution with simultaneous charging and discharging.

$$\sum_{p} xp_{n,p,s,t} + \sum_{n2}\sum_{l}\left(xl_{n2,n,l,s,ImT_{n2,n,t}} \cdot LE_{n,n2,l} - xl_{n,n2,l,s,t}\right) + \sum_{st}\left(xdc_{n,st,s,t} - xch_{n,st,s,t}\right) = ELD_{n,s,t} \quad \text{(A.7)}$$

$$LE_{n,n2,l} = (1 - LOS_l)^{\frac{DIS_{n,n2}}{1000}} \quad \text{(A.8)}$$

Where: $\boldsymbol{ELD_{n,s,t}}$: electric load at local time *t* in season *s* in node *n* [MW], $\boldsymbol{LE_{n,n2,l}}$: cross-border transmission efficiency of transmission line type *l* between node *n* and *n2*, $\boldsymbol{LOS_l}$: transmission losses of line type *l* [per thousand km], $\boldsymbol{DIS_{n,n2}}$: transmission distance between node *n* and *n2* [km], $\boldsymbol{ImT_{n2,n,t}}$: local time at the origin of electricity imports, defined as:

$t+TimD_{n2,n}+24$	for $t+TimD_{n2,n} < 0$;
$t+TimD_{n2,n}$	for $0 \leq t+TimD_{n2,n} < 24$;
$t+TimD_{n2,n}-24$	for $t+TimD_{n2,n} \geq 24$;

and $\boldsymbol{TimD_{n2,n}}$: time difference between nodes (e.g., $TimD_{CH\text{-}N,KR}$=-1).

Installable capacity constraint

Installable capacity of each technology is constrained by its minimum and maximum deployable limits. (see Section 4.3.2 and Section 4.3.3 for initial capacity and upper limit assumptions).

$$PMI_{n,p} \leq kp_{n,p} \leq PMA_{n,p} \quad \text{(A.9)}$$

$$SMI_{n,st} \leq kst_{n,st} \leq SMA_{n,st} \quad \text{(A.10)}$$

$$LMI_{n,n2,l} \leq kl_{n,n2,l} \leq LMA_{n,n2,l} \quad \text{(A.11)}$$

Where: $\boldsymbol{PMI_{n,p}}$: initial capacity of power plant type *p* in node *n* [kW], $\boldsymbol{PMA_{n,p}}$: capacity upper limit of power plant type *p* in node *n* [kW], $\boldsymbol{SMI_{n,st}}$: initial capacity of storage type *st* in node *n* [kW], $\boldsymbol{SMA_{n,st}}$: capacity upper limit of storage type *st* in node *n* [kW], $\boldsymbol{LMI_{n,n2,l}}$: initial capacity of transmission line type *l* between node *n* and *n2* [kW], $\boldsymbol{LMA_{n,n2,l}}$: capacity upper limit of transmission line type *l* between node *n* and *n2* [kW].

Output constraint

Equations (A.12)~(A.16) constrain output of power plant, storage and transmission lines. The output of power generation technologies, except wind power and PV, are constrained to their available capacity [equation (A.12)]. For wind and PV, the seasonal hourly availability profiles (*ROF*) are exogenously given in equation (A.13). These profiles for Gobi Desert (GD) are estimated in Section 4.3.2 based on observation data (Elliott, et al., 2001). The left part of the equation (A.13) indicates two destinations for output power from wind and PV: power supplied to grid (*xp*) or suppressed (*de*). Equation (A.14) constrains the charge to or discharge from storage facilities to their available power capacity (kW-capacity). Equation (A.15) constrains stored electricity to the energy capacity (kWh-capacity), i.e., reservoir capacity of pumped hydro.

$$xp_{n,p,s,t} \leq PAV_p \cdot kp_{n,p} \quad (p = 1, \dots, 5,8,9) \tag{A.12}$$

$$xp_{n,p,s,t} + de_{n,p,s,t} = ROF_{n,p,s,t} \cdot kp_{n,p} \quad (p = 6,7) \tag{A.13}$$

$$xch_{n,st,s,t} + xdc_{n,st,s,t} \leq STAV_{st} \cdot kst_{n,st} \tag{A.14}$$

$$ste_{n,st,s,t} \leq STAV_{st} \cdot CRT_{st} \cdot kst_{n,st} \tag{A.15}$$

$$xl_{n2,n,l,s,t} + xl_{n,n2,l,s,t} \leq LAV_l \cdot kl_{n,n2,l} \tag{A.16}$$

Where: $\boldsymbol{PAV_{n,p}}$: availability factor of power plant type *p* (*p*=1,...,5,8,9), $\boldsymbol{ROF_{n,p,s,t}}$: output profile of intermittent renewable(wind and PV) energy at local time *t* in season *s*, $\boldsymbol{STAV_{st}}$: availability factor of storage type *st*, $\boldsymbol{CRT_{st}}$: maximum ratio of kWh to kW of storage type *st*, $\boldsymbol{LAV_{st}}$: availability factor of transmission line type *l*.

Ramping constraint for thermal power plants (Nuclear and fossil fuel-fired)

The model considers technology-specific ramping constraints for nuclear and fossil fuel-fired plants. For technical reasons, each technology has its own controllability, with output of these power plants changeable within their ramping capabilities. Ramping up and ramping down limits are modelled as follows in this study.

$$xp_{n,p,s,t} \leq xp_{n,p,s,t-1} + LFR_p \cdot kp_{n,p} \quad (t \neq 0) \tag{A.17}$$

$$xp_{n,p,s,0} \leq xp_{n,p,s,23} + LFR_p \cdot kp_{n,p} \tag{A.18}$$

$$xp_{n,p,s,t} \geq xp_{n,p,s,t-1} - LFR_p \cdot kp_{n,p} \quad (t \neq 0) \tag{A.19}$$

$$xp_{n,p,s,0} \geq xp_{n,p,s,23} - LFR_p \cdot kp_{n,p} \tag{A.20}$$

Where: $\boldsymbol{LFR_p}$: maximum load following rate of power plant type *p* [/hour].

Ramping constraint for thermal power plants (Nuclear and fossil fuel-fired)

Equation (A.21) requires that thermal plants generate electricity at no less than their minimum output threshold. The model calculates the minimum output threshold by multiplying minimum output rate (*MOL*) and daily maximum output (*mp*) as described in equation (A.21). Daily maximum output for each plant type in each season is determined by equation (A.22).

$$xp_{n,p,s,t} \geq mp_{n,p,s} \cdot MOL_p \tag{A.21}$$

$$mp_{n,p,s} \geq xp_{n,p,s,t} \tag{A.22}$$

Where: $\boldsymbol{MOL_p}$: minimum output rate of operation of power plant type *p*.

Stored energy balance

Equation (A.23)~(A.24) relates power charge (*xch*), power discharge (*xdc*) and the level of stored electricity (*ste*). Self-discharge loss and charge/discharge efficiency are considered in this equation.

$$\begin{aligned} ste_{n,st,s,t} = (1 - SDR_{st}) \cdot ste_{n,st,s,t-1} \\ +(\sqrt{CEF_{st}} \cdot xch_{n,st,s,t} - xdc_{n,st,s,t}/\sqrt{CEF_{st}}) \cdot TW_t \quad (t \neq 0) \end{aligned} \tag{A.23}$$

$$\begin{aligned} ste_{n,st,s,0} = (1 - SDR_{st}) \cdot ste_{n,st,s,23} \\ +(\sqrt{CEF_{st}} \cdot xch_{n,st,s,0} - xdc_{n,st,s,0}/\sqrt{CEF_{st}}) \cdot TW_t \end{aligned} \tag{A.24}$$

Where: $\boldsymbol{SDR_{st}}$: self-discharge rate of storage type *st*, $\boldsymbol{CEF_{st}}$: cycle efficiency of storage type st, $\boldsymbol{TW_t}$: length of time slice *t* [hour] (=1hour).

Capacity reserve constraint for city nodes

Constraint (A.25) ensures a certain level of capacity reserve margin in city node for a reliable power supply. There should be enough excess generation/storage capacity and domestic transmission at city node to cover demand plus the reserve margin.

$$\begin{aligned} \sum_p kp_{n,p} \cdot PCC_p + \sum_{st} kst_{n,st} \cdot STCC_{st} + \sum_{l,n2 \in N_n} \left(xl_{n2,n,l,s,t} \cdot LE_{n,n2,l} - xl_{n,n2,l,s,t}\right) \\ \geq (1 + RVM_n) \cdot ELD_{n,s,t} \quad (n = 1, \dots, 8) \end{aligned} \tag{A.25}$$

Where: $\boldsymbol{RVM_n}$: reserve margin in node *n*, $\boldsymbol{PCC_p}$: capacity credit of power plant type *p*, $\boldsymbol{STCC_{st}}$: capacity credit of storage type *st*, $\boldsymbol{N_n}$ = set of nodes located in the same economy as node *n*.

Upper constraints of net-imports for city nodes

In general, each power service area needs to be prepared for transmission interruptions. Thus, in the scenarios in this study, the net transmission inflows at each city node (left part of the equation) are limited to be less than the reserve margin level (*NIS*=*RVM*).

$$\sum_{l,n2}\left(xl_{n2,n,l,s,t} \cdot LE_{n,n2,l} - xl_{n,n2,l,s,t}\right) \leq NIS_n \cdot ELD_{n,s,t} \quad (n = 1, \dots, 8) \tag{A.26}$$

Where: $\boldsymbol{NIS_n}$: maximum share of net imports in node *n* (we assume the reserve margin for the scenarios in this study).

Additional hydro power export constraints

As explained in the *RuHyd* scenario in Section 4.2, this study considers additional hydro developments in Russia Far East (RU-FE) and Russia Siberia (RU-SI) for exporting to foreign nodes. This equation ensures that power exports from these nodes should be larger than the output power of additional hydro.

$$\sum_{l,n2 \notin N_n} xl_{n,n2,l,s,t} \geq \sum_{p=8}^{9} xp_{n,p,s,t} \tag{A.27}$$

Transmission line capacity constraints for supply nodes

Equation (A.28) requires each supply node (GD and RU-FE) to have enough transmission capacity to deliver the output of the installed generation capacity in the node. This constraint may be active especially in the *Gobitec* and *Gobitec+RuHyd* scenarios, where there are minimum constraints on generation capacity in the Gobi Desert (GD) node. This constraint forces the total GD transmission capacity to at least match the total GD generation capacity.

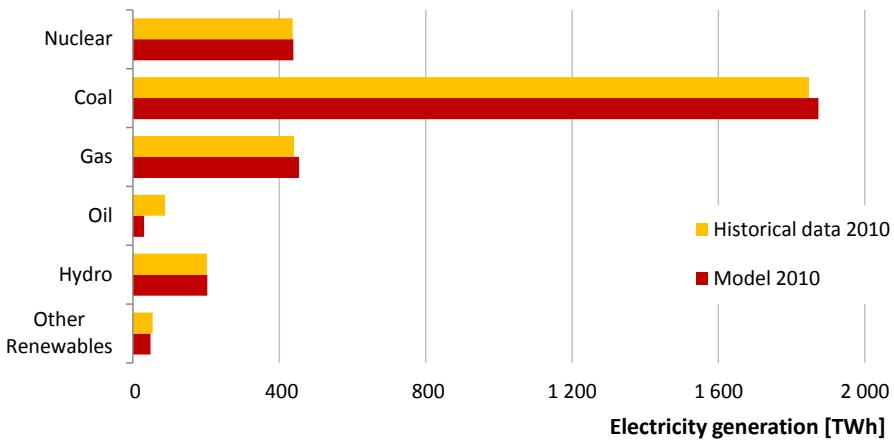
$$\sum_{l,n2} kl_{n,n2,l} \geq \sum_{p} kp_{n,p} \quad (n = 9, 10) \tag{A.28}$$

A.2 MODEL VALIDATION

In order to validate the model's ability to properly assess the real-world power system, we performed a simulation of the NEA power system of 2010, the most recent year before the Great East Japan Earthquake. The installed capacity of power plants, storage and cross-border transmission line is calibrated to historical data (JEPIC, 2012). Costs and fuel prices for 2010 are based on IEA (2010), IEA (2014a) and Energy and Environment Council (2011). Historical average efficiency of fossil fuel-fired plants is estimated using IEA (2014b). No carbon tax is assumed, and other parameters are the same as shown in Section 4.3.

Figure A1 illustrates modelled generated electricity and statistical data (JEPIC, 2014a). So-called base load and middle load plants (nuclear, coal, gas and hydro) shows relatively a good fit. By contrast, the model tends to underestimate peak load plants (oil). As reported in Schaber, et al. (2012), this is because of the deterministic nature of the optimisation model. Probabilistic aspects, such as unforeseen forecast errors or power plant outages, are not considered in the model, while peak load plants are often operated to balance electricity demand and supply in those events.

Figure A1 Comparison of modelled generated electricity and historical data in Northeast Asia



Source: APERC analysis.

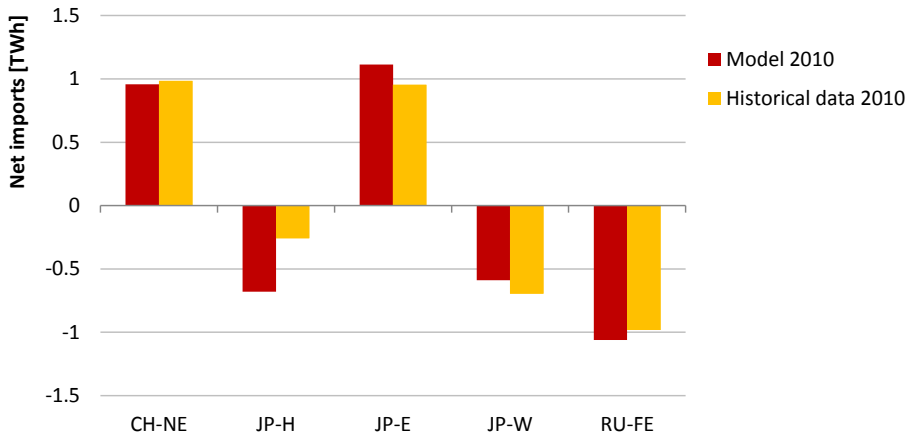
The model reproduces similar trends of cross-border electricity trade as shown in Figure A2. The observed differences might be because the actual power trade is not always scheduled based on cost-optimisation, as well as because the model simplifies several aspects, especially in terms of simplified modelling of power transportation (see Section 4.1) or temporal resolution.

This study deduces electricity prices from average marginal generating costs, which approximately describe the regional retail price gap (Figure A3). We referred to JEPIC (2012) for the price in China, METI (2014b) for Japan, KESIS (2015) for Korea and RAO

Energy System of East (2013) for Russia Far East area. The computed marginal generating costs tend to be lower than the actual prices (i.e. 4c/kWh in Japan and 1c/kWh in Russia Far East). This is partly because of the costs, taxes or subsidies not explicitly included in our model. The actual electricity price in Korea is lower than the calculated average marginal costs. This is probably because Korea government regulation holds electricity price at level lower than the actual generating costs. In fact, from 2008 to 2012, Korea Electric Power Corporation was in a chronic state of deficit (KEPCO, 2015).

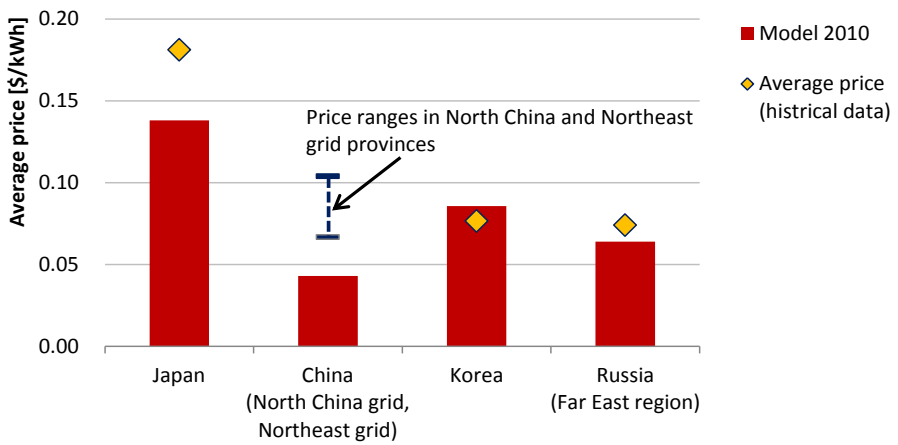
The generated electricity and cross-border trades in the benchmark results are insensitive to fuel price changes: a considerable price increase (90% for coal and 20% for gas) does not have major impacts on the results.

Figure A2 Modelled net imports and historical data



Source: APERC analysis.

Figure A3 Comparison of the average retail electricity prices with the modelled average marginal costs of power generation



Source: APERC analysis.

A.3 DISCUSSION ON CAPAITY RESERVE CONSTRAINT

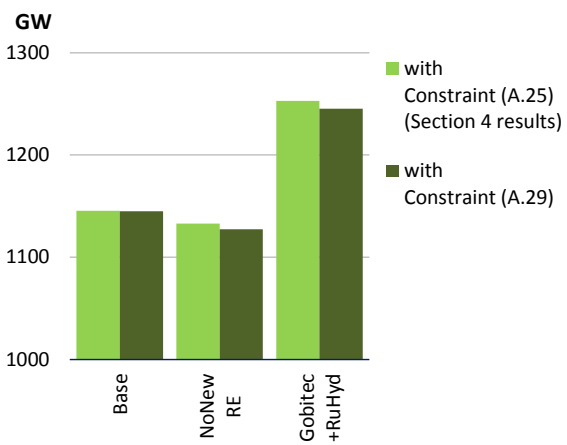
Equation (A.25) does not take into account the demand levelling and capacity saving benefits from non-domestic transmissions. This is because of our policy based on the safer side from energy security perspectives. In this section, we additionally conduct an analysis to discuss these benefits in NEA. We replace the Constraint (A.25) with the following Constraint (A.29). The red part is changed from '$n2 \in N_n$' to '$n2$'. Constraint (A.25) assumes that only domestic electricity trades contribute to demand levelling and capacity saving, while (A.29) considers non-domestic trades as well. We ran three scenarios (the *Base*, *NoNewRE* and *Gobitec+RuHyd*) with Constraint (A.29).

$$\sum_{p} kp_{n,p} \cdot PCC_p + \sum_{st} kst_{n,st} \cdot STCC_{st} + \sum_{l,n2} \left(xl_{n2,n,l,s,t} \cdot LE_{n,n2,l} - xl_{n,n2,l,s,t} \right) \geq (1 + RVM_n) \cdot ELD_{n,s,t} \quad (n = 1, \dots, 8) \tag{A.29}$$

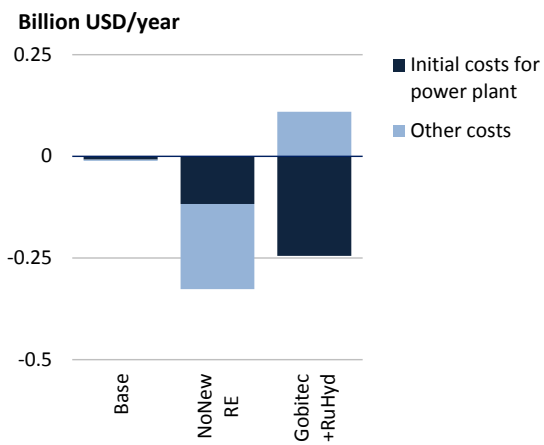
The results with Constraint (A.29) shows capacity saving effects (Figure A4a)); however, its changes appears to be modest. Compared to (A.25) results, total installed capacity in NEA is reduced by 6GW and 8GW with (A.29) in the *NoNewRE* and *Gobitec+RuHyd* scenarios, respectively. Yet, these capacity savings are equivalent only to 0.5~0.6% reductions, resulting in slight impacts on total cost (-0.03~-0.08%. see Figure A4b)). Because of the small time difference (maximum two hours) in NEA, peak-hours still occur more or less simultaneously in each region (Figure 42). This would be the main cause of the modest demand levelling and capacity saving benefits. The result implies that the benefits of interconnections are mainly due to other factors, such as low-cost electricity in the exporting regions. The result also implies that the findings obtained through Section 4 are robust to these formulations.

Figure A4 Comparison of the results with Constraint (A.25) and with (A.29)

a) Total installed capacity



b) Changes in yearly total cost from Constraint (A.25) to (A.29)



Source: APERC analysis.

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