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ELECTRIC POWER GRID INTERCONNECTIONS IN THE APEC REGION

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FOREWORD

Enhanced links between the electric power grids of APEC economies hold significant promise to reduce the costs of electricity generation and its impacts on the environment. Yet useful new transmission lines often face difficult regulatory obstacles, as well as complex laws and rules that may inhibit trade. APERC has undertaken this study to give policy makers a better understanding of the potential benefits from strengthened power interconnections in the APEC region, as well as some practical steps that might be taken to help ensure that those benefits can be realised.

This report is an independent study and does not necessarily reflect the views or policies of the APEC Energy Working Group or individual APEC members. But we hope it will highlight the important role of power grids in providing electricity to APEC economies in a sustainable fashion, as grids are key to providing power that consumers can afford and the environment can handle.

Masaharu Fujitomi
President
Asia Pacific Energy Research Centre

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LIST OF ABBREVIATIONS

AC	alternating current
AIMS	ASEAN Interconnection Master Plan Study
AMEM	ASEAN Ministers of Energy Meeting
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of South East Asian Nations
Bcm	billion cubic metres (one thousand Mcm)
BPL	Berakas Power Company (Brunei Darussalam)
Bt	billion tonnes (one thousand Mt)
Btu	British thermal unit
CFC_{11}	chlorofluorocarbon-11
CO_2	carbon dioxide
DC	direct current
DES	Department of Electrical Services (Brunei Darussalam)
DPRK	Democratic People's Republic of Korea (North Korea)
EDC	Electricité du Cambodge (Cambodia)
EDL	Electricité du Laos
EDT	Eastern Daylight Time (Greenwich Mean Time – 5 hours)
EGAT	Electricity Generating Authority of Thailand
EPCO	electric power company
ESA	Energy Supply Act of 1990 (Malaysia)
EVN	Electricity of Viet Nam
FERC	Federal Energy Regulatory Commission (United States)
GDP	gross domestic product
GW	gigawatt (one billion watts or one million kW)
GWh	gigawatt hour (one billion watt-hours or one million kWh)
HAPUA	Heads of ASEAN Power Utilities and Authorities
Hz	hertz (cycles per second)
IEEJ	Institute of Energy Economics, Japan
IPP	independent power producer
ISO	independend system operator
KEPCO	Korea Electric Power Company
km	kilometres
KOGAS	Korea Gas Corporation
kt	kilotonne (one thousand tonnes)
kV	kilovolt (one thousand volts)
kW	kilowatt (one thousand watts)
kWh	kilowatt hour (one thousand watt-hours or 3,412 Btu)

LNG	liquefied natural gas
LOLP	loss of load probability
MBtu	million British thermal units
Mcm	million cubic metres
MEPE	Myanmar Electric Power Enterprise
MISO	Midwest Independent System Operator (United States)
MOCIE	Ministry of Commerce, Industry and Energy (South Korea)
MOU	memorandum of understanding
MSE	multi-state entity
Mt	megatonne (one million tonnes)
MW	megawatt (one thousand kW)
MWh	megawatt hour (one thousand kWh)
NAFTA	North American Free Trade Agreement
NERC	North American Electric Reliability Council
NOx	nitrogen oxides
NPC	National Power Corporation (Philippines)
PLN	Perusahaan Listrik Negara (Indonesia)
PPA	power purchase agreement
RFE	Russian Far East
RFF	Resources for the Future
ROK	Republic of Korea (South Korea)
RTO	Regional Transmission Organisation
SOx	sulphur oxides (including sulphur dioxide)
Tcm	trillion cubic metres (one million Mcm)
TLR	transmission loading relief
TNB	Tenaga Nasional Berhad (Malaysia)
TWh	terawatt hour (one trillion watt-hours or one billion kWh)
WGA	Western Governors Association (United States)

EXECUTIVE SUMMARY

BENEFITS OF POWER GRID EXPANSION FOR THE APEC REGION

Electric power grids have brought substantial benefits to the APEC region and hold the potential to provide further benefits if strengthened and extended. The benefits include more reliable power supply, lower electricity costs to consumers, and reduced environmental impacts.

Power grid enhancements can ***make electric supply more reliable*** by improving the ability of economies to cope with the outage of specific generating units or types of generating units, as well as by limiting the scope of power outages. Two recent examples are instructive:

- In Japan, a strengthened power grid, with enhanced interregional transfer capacity, could improve the economy's ability to deal with power plant outages. Available firm long-term transfer capacity is far less than the amount of nuclear generating capacity in several areas. If nuclear power plants were placed out of service in those areas, as they were in Tokyo during 2002 and 2003, enhanced transmission links could thus be essential to the continued reliable provision of electric power.
- In North America, a strengthened power grid, with a heightened voltage profile, could improve the ability of Canada and the United States to limit the geographic scope of power outages. The historic blackout of August 2003, which affected service to some 50 million citizens, did not cascade to areas with strong grids.

Enhanced power grids can ***lower electricity costs*** by reducing needs for electric generating capacity and allowing cheaper fuel to be substituted for more expensive fuel. Grids lower needs for generating capacity by allowing peak demand in one area to be served in part by spare capacity in a neighbouring area where demand is not at its peak. Grids lower fuel costs by allowing generation from nuclear, hydro and coal-fired power plants to displace generation from gas-fired plants. There are historical and potential cost savings from power grids across the APEC region:

- In Southeast Asia, eleven proposed power links among ASEAN economies have been found to be cost-effective. For seven of the links, projected to cost $356 million, it is estimated that generating capacity costs would be lowered by $1,018 million, yielding net benefits of $662 million. For proposed power links in the Greater Mekong Subregion, net savings have been estimated at $914 million.
- In Northeast Asia, several proposed new power links could reduce electricity costs. For example, a link between Russia, China and Korea, allowing more efficient use of nuclear and fossil-fuelled capacity, could reduce costs by $1 billion per annum. In Japan, the existing power grid has reduced generating capacity requirements by about 3 percent, which translates to a capital cost savings of roughly $7 billion.
- In the United States, wholesale power trade over the grid has reduced generating costs by some $13 billion. If existing congestion on the transmission grid were relieved, generating costs might be reduced by roughly another $1 billion per year. Benefits of power trade may be greater than anticipated, as on the Pacific Intertie, where slower demand growth in the Northwest has freed extra hydropower for export to California. Yet benefits are also sensitive to fuel price assumptions; if gas prices are high, displacement by coal will be greater, and so will fuel cost savings.
- In Latin America, proposed power links between Peru and neighbouring economies are projected to yield annual operating savings about equal to their investment cost.

Extension of power grids can ***benefit the environment*** by allowing forms of power generation with lower atmospheric emissions to replace types of generation with higher emissions. For example, nuclear and hydropower have much lower emissions than gas-fired power, which in turn has much lower emissions than conventional coal-fired power. There are several regional examples:

- In Southeast Asia, gas-fired power from Indonesia and Malaysia may displace coal-fired power elsewhere. Hydropower from China, Laos and Myanmar holds promise to reduce emissions from fossil-fuelled generation in Thailand and Viet Nam.
- In Northeast Asia, hydro and wind resources in China and Russia could be used to displace fossil-fuelled generation. Nuclear plants in Japan, Korea or Russia could also reduce fossil-fuelled generation in neighbouring economies.
- In North America, the power grid facilitates displacement of fossil-fuelled power by nuclear and hydropower, reducing emissions of atmospheric pollutants. But the grid also allows cheap coal to displace more expensive gas, raising emissions.

DEALING WITH OBSTACLES TO POWER GRID EXPANSION IN APEC

There are two sets of serious obstacles to power grid expansion in APEC economies. One type of obstacle relates to the complexity of zoning and environmental regulations, which may make it difficult to obtain approval for new electric power lines in all the jurisdictions through which they run. Another type of obstacle relates to different rules and regulations in different economies, which are often inconsistent with each other and do not always promote investment.

Several options are available to ***streamline the siting*** of transmission facilities:

- An open planning process, which solicits the views of all interested parties on how best to address a transmission need, reduces opposition in two ways. It allows all parties to be satisfied that their views have been considered. It also allows those proposing new lines to suit their proposals to a broader spectrum of interests.
- Consideration of a broad range of options, which focuses on how best to meet power needs rather than on getting a particular project built, can engage the public to help the transmission company find a solution that meets everyone's requirements. It also allows the applicant to show that a project is the best way to meet the need.
- Regional planning bodies can create an efficient review process for proposed new transmission lines. All entities that have legal jurisdiction over siting can work with the same documents and establish common timelines for reviews, eliminating the need for duplicate applications and review meetings across jurisdictions.

There are also several ways to ***harmonise laws and rules*** related to transmission grids:

- Reciprocal recognition of licences for participants in cross-border projects;
- Agreements to avoid double-taxation that can make cost-effective projects unprofitable;
- Clear and fair rules for dispute resolution among parties to cross-border trade;
- Common standards for health, safety, environment, and consumer protection;
- Flexible movement of managerial and professional labour to help build transmission lines;
- Allowance for the unrestricted flow of funds and repatriation of profits.

An additional issue related to cross-border power trade is the differing pace of regulatory reform in power markets across APEC economies. Some economies are moving faster than others to allow wholesale competition among generators and retail competition among suppliers. This could discourage power trade if independent power producers in rapidly reforming economies feared cross-subsidisation of generation by integrated power monopolies in other economies. Conversely, power trade might be discouraged if integrated power monopolies in slowly reforming economies feared competition from independent generators in more rapidly reforming economies. In practice, however, it appears that if the potential reliability and economic benefits of power trade are compelling, parties will find a way to bring trade about regardless of regulatory incongruities.

INTRODUCTION

THE SETTING FOR EXPANSION OF ELECTRIC POWER GRIDS

Enhanced electric power grids can make energy supplies both more secure and less costly. Economies and regions vary in the ease with which they can build different types of power plants and in their natural endowments of fuel on which power plants run. Different places have different amounts of coal, gas, nuclear and renewable resources, as well as different cost structures for building coal-fired, gas-fired, nuclear and renewable power plants. They also have different demand patterns, so that some areas may be near their peak usage of available electric generating capacity supplies while other areas have significant amounts of spare capacity. Consequently, enhanced interconnections and trade within and among economies can significantly lower the overall costs of power production and diversify sources of power supply. The result is greater energy security since increased costs or reduced availability for any given fuel or power plant will have less impact on the overall cost and availability of electric power. Stronger grids may also open up new avenues of competition among electricity suppliers, further limiting power costs to industry and consumers.

On the other hand, enhancement of power grid links requires costly investment, and the specific economic and security benefits are often hard to measure. Typically, it should be technically feasible to enhance interconnections between two or more electricity systems regardless of the frequencies on which they operate or the regulatory regimes to which they are subject. With back-to-back direct current linkages, even systems with entirely different voltages and frequencies can be interconnected. But new transmission lines and subsystems are designed to last for decades, and the supply and demand situations of the areas to be interconnected may shift considerably over time. This means that while the up-front costs of transmission enhancements are known quite clearly in advance, the economic and security benefits cannot be estimated precisely. As a result, it may be hard to obtain the necessary financing unless the benefits can be shown to be compelling.

In addition, there may be difficult political, institutional, and regulatory obstacles to overcome if stronger interconnections are to be put in place. What guarantees do the parties have that the enhanced transmission links will be operated in a cooperative fashion once completed, in a manner that is likely to benefit all concerned? What guarantees do financial institutions have that their loans for the facilities will be repaid from revenues received? How will the costs be allocated across different economies and classes of customers? Who will reap the associated cost savings? It may well be necessary to put a bilateral or multilateral institutional framework in place to address such issues, with governments involved to ensure that the framework is implemented.

Several proposals have been under discussion for enhanced power grids in the APEC region. Some relate to power grids within APEC economies, while others relate to new links between them:

- In Japan, there has been discussion of enhanced linkages between eastern and western power grids, as well as among electricity service areas within each grid, to boost security against potential supply shortfalls, particularly in view of the forced shutdown of most nuclear power plants in the Tokyo area during 2002 and 2003.
- In North America, extensive power blackouts in the summer of 2003 focused increased attention on the need to move electricity reliably over the power grid, while the National Energy Plan and National Grid Study in the United States highlighted the importance of grids in keeping power supply secure and affordable.
- In Southeast Asia, heads of member states in the Association of Southeast Asian Nations (ASEAN) have endorsed an ASEAN Power Grid, and an ASEAN Interconnection Master Plan Study has selected eleven projects for implementation through 2020; these would link APEC members Singapore, Malaysia, Indonesia, Thailand and Vietnam, as well as neighbouring Cambodia, Myanmar and Lao People's Democratic Republic, into three clearly-defined power networks.

- In Northeast Asia, the United Nations Economic and Social Commission for Asia and the Pacific (ESCAP) organised an expert group which issued the Khabarovsk communique urging enhanced power links among Russia, China, Korea and Japan.[1]
- In South America, transmission lines are planned to link Peru with its neighbours in the Andean Nations Community, as well as to link Chile with Peru and Argentina.

As APEC energy ministers noted in Mexico City in 2002, "cross-border inter-connections of energy systems have the potential to bring great economic and technical benefits to our energy systems and to provide significant energy trade opportunities."[2] The potential benefits of enhanced power grid links, and practical steps toward realizing them, should therefore be explored in depth.

STUDY SCOPE AND OBJECTIVES

This study examines the potential for enhanced power system interconnections both within and among APEC economies. If focuses in particular on enhanced transmission links in Japan, North America, South America, Northeast Asia and Southeast Asia. The report assesses possible benefits of stronger power grid links in terms of the reliability of service, power system economics, and the environmental impacts of power production. It also describes some of the legal, regulatory and institutional obstacles to enhancement of power grids, as well as ways to streamline regulations and harmonise laws to deal with these obstacles effectively. Finally, it examines how power grid expansion might be affected by economies having different degrees of power market competition.

OUTLINE OF THE REPORT

After this introduction, the report describes existing or proposed power grids in Japan, North America, South America, Northeast Asia and Southeast Asia that are the geographic focus of its analysis. It then assesses the reliability benefits, economic benefits and environmental benefits of power grid enhancements in three succeeding chapters. In terms of reliability, the focus is on how enhanced transmission links might reduce the likelihood of blackouts and improve the ability of economies to respond to a crisis in which a particular type of power plant is called out of service. In terms of economics, the focus is on the extent to which greater power grid interconnections might reduce the overall costs of providing electric service and reduce cost disparities among different areas. In terms of the environment, the focus is on whether enhanced transmission links might significantly reduce atmospheric emissions of sulphur dioxide, nitrogen oxides and carbon dioxide.

In the final three chapters, the report examines ways of streamlining regulation to facilitate power grid expansion within APEC economies, ways of harmonising laws and rules to boost electricity trade among APEC economies, and the impact on power grids of power industry reform. The discussion of regulatory streamlining focuses on ways of accommodating environmental and zoning interests associated with transmission line construction in a thorough yet efficient fashion. The discussion of harmonising laws and rules relates to reducing conflicts or inconsistencies that increase the risk of investment in power lines and may therefore deter it. Finally, the discussion of power industry reform examines whether the fact that some economies have more competitive markets than others can be expected to slow the progress of cross-border electricity trade.

[1] ESCAP (2001).

[2] APEC Energy Ministers (2002).

POWER GRID CHARACTERISATION

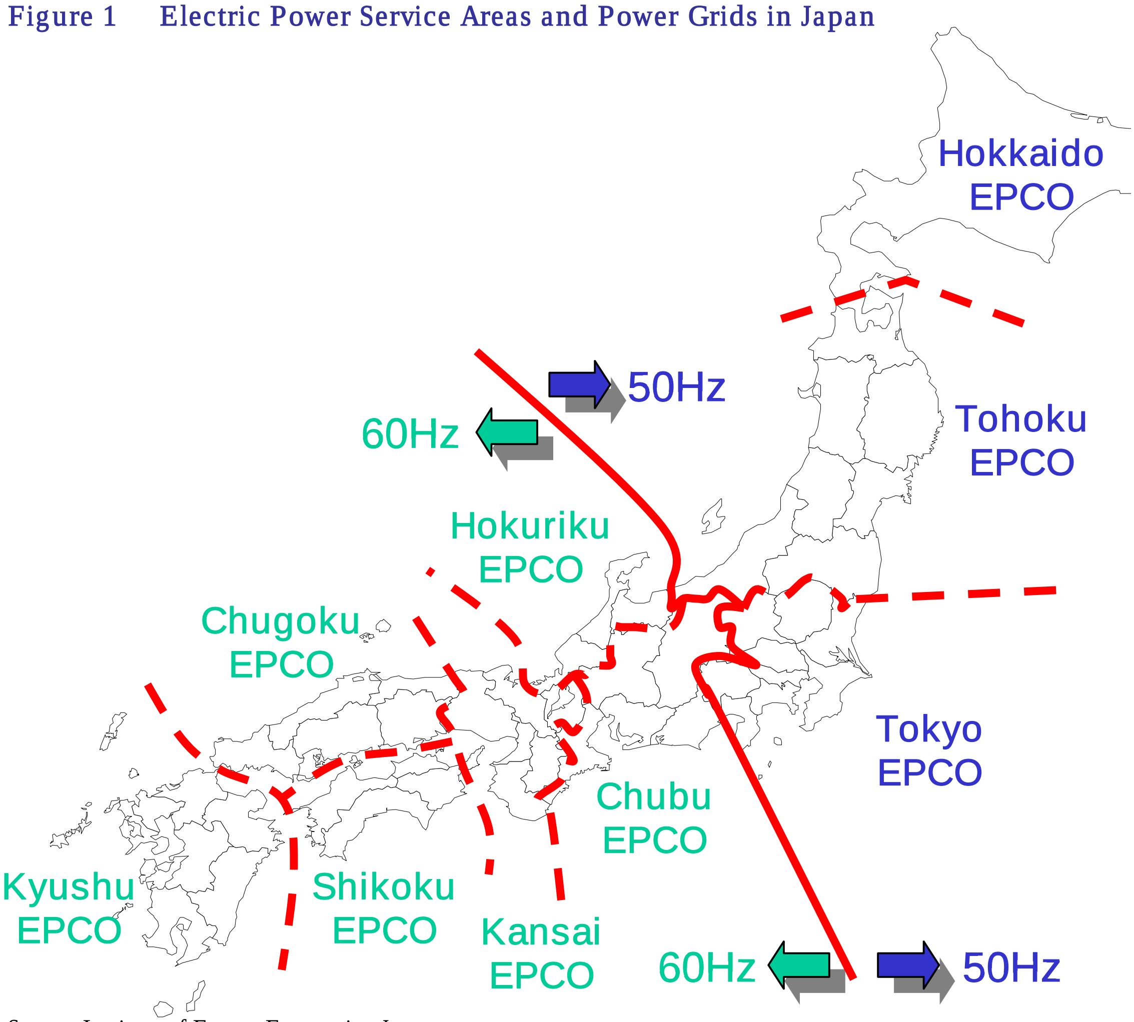
INTRODUCTION

This study focuses on five major power grids in the APEC region. Two of the grids, in Japan and North America, are well established and have operated under common guidelines for many decades. The other grids, in South America, Northeast Asia and Southeast Asia, mainly involve hypothetical or planned links between several different economies with widely varying legal systems and technical practices. As a foundation for examining the potential economic and reliability benefits of building or enhancing each grid, as well as the legal and regulatory issues that may arise in doing so, this chapter briefly describes what each grid looks like today or might look like if built.

THE POWER GRID IN JAPAN

Japan has ten distinct electricity service areas, each traditionally dominated by a vertically integrated utility. As shown below, three of the areas belong to a 50 Hz synchronous grid to the east, while six belong to a separate 60 Hz grid to the west (the tenth area, Okinawa, is not shown).

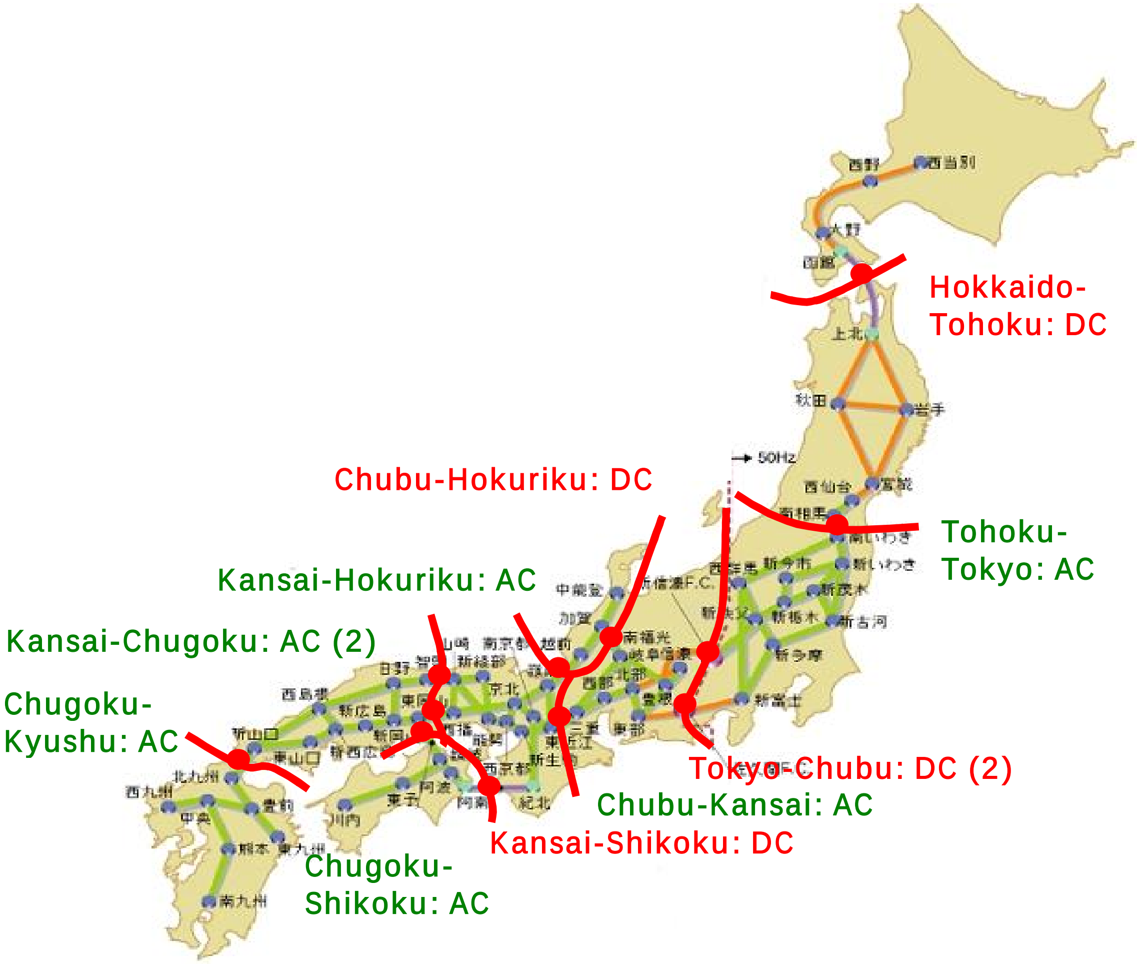
Figure 1 Electric Power Service Areas and Power Grids in Japan



Source: Institute of Energy Economics, Japan

Within each service area, transmission links are quite extensive, as the grid was developed according to the precept that each area should be basically self-sufficient. Nonetheless, there are several transmission links between the various service areas. In the figure below, alternating current transmission lines are labelled in green while direct current lines, including those that link together the eastern and western synchronous grids, are labelled in red. Trade between the service areas, very nearly all of it bilateral, accounts for about 7 or 8 percent of electricity generated. [3]

Figure 2 Major Transmission Links Between Service Areas in Japan in 2003



Source: Central Research Institute of the Electric Utility Industry (CRIEPI), Japan

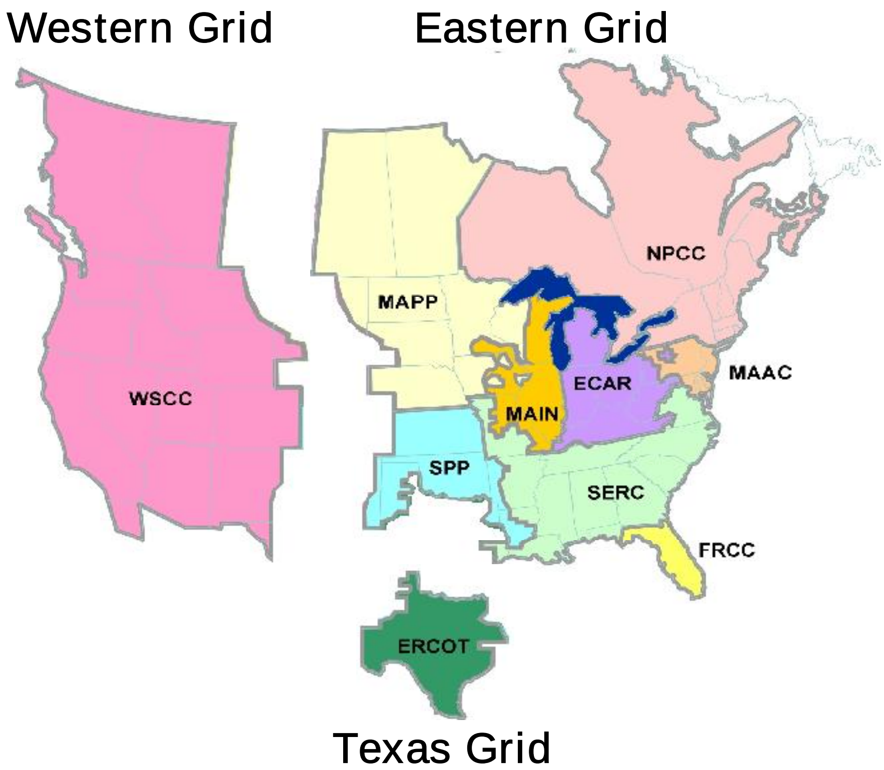
THE POWER GRID IN NORTH AMERICA

North America is divided into three distinct interconnections: Eastern, Western and Texas. Each interconnection operates in synchronous fashion, with voltages normally kept within narrow tolerances. There are also ten distinct reliability areas, each of which has primary responsibility for maintaining reliable service. Further, there are some twelve standard market operators (SMOs). There are over a hundred retail electric companies with vertically integrated generation, transmission, distribution and retail sales. There are thousands of municipal and cooperative and other utilities which together satisfy a quarter of electricity demand. Finally, there are many independent power producers that accounted for a quarter of US electricity generation in 2002. [4]

[3] Kurihara (2003).

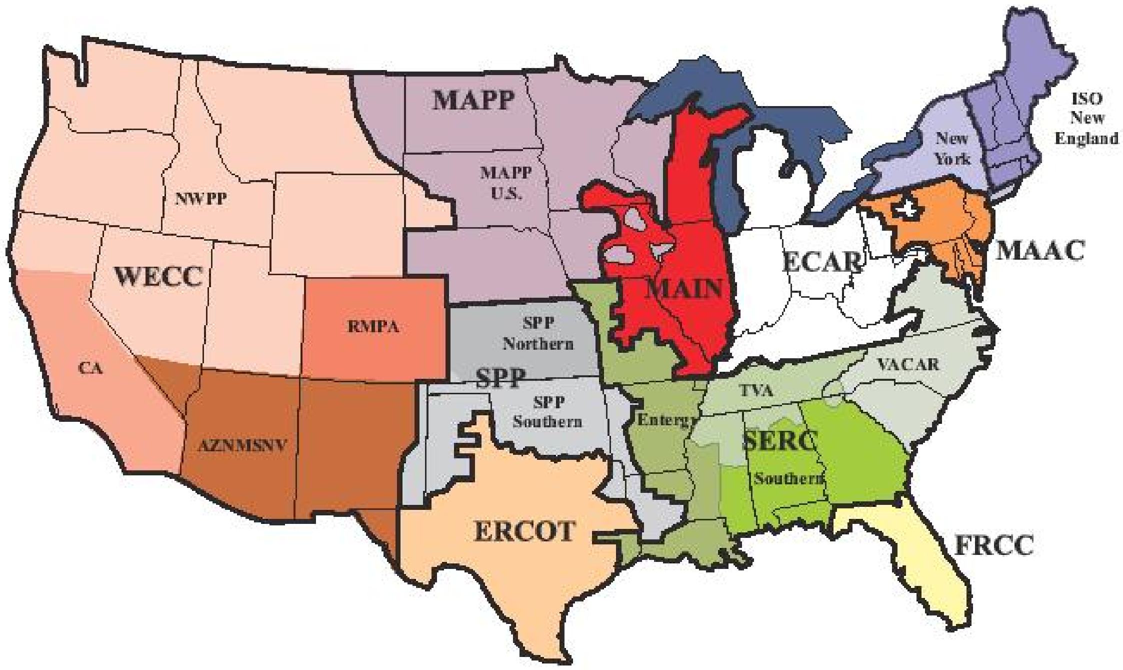
[4] Nugent (2002).

Figure 3 The Three Power Interconnections of North America



Source: North American Electric Reliability Council

Figure 4 United States Power Subregions and Independent System Operators



Source: United States Department of Energy

POWER GRID PROPOSALS FOR SOUTH AMERICA

Plans have recently been put in place for major transmission links in South America involving APEC economies Chile and Peru. Some are arranged bilaterally between Chile and Argentina, others under the auspices of the Andean Nations Community (ANC), a consortium linking Peru with Bolivia, Colombia, Ecuador, and Venezuela. In 2002, most of the ANC economies signed an agreement to promote interconnections, and the ANC established a working group to design a common electricity market with free trade among them. Planned lines are shown in Figure 5.

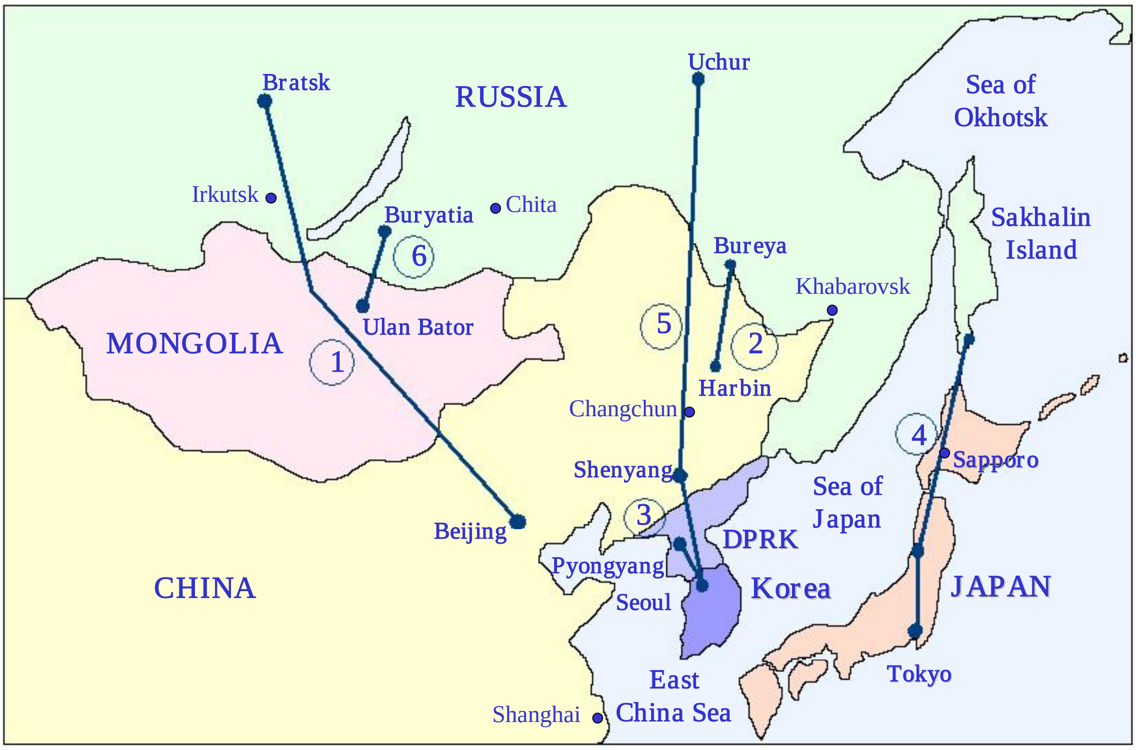
Figure 5 New and Planned Transmission Links Involving APEC South America

Source: National Energy Commission (Chile)

POWER GRID PROPOSALS FOR NORTHEAST ASIA

Several proposals have been made for power grid interconnections among the economies of Northeast Asia, but none has received what might be termed official endorsement by governments. Thus, the proposals may so far be regarded as speculative in nature and subject to substantial revision. Nonetheless, specific ideas have been put forth by experts for transmission links between Russia and China (linking East Siberia with Beijing and the Russian Far East with Harbin), between Russia and Mongolia, between Russia (Sakhalin) and Japan, and between North Korea (People's Democratic Republic of Korea or DPRK) and South Korea (Republic of Korea or ROK).[5]

Figure 6 Some Potential Elements of a Northeast Asian Power Grid



Source: Podkovalnikov (2002).

Table 1 Specifications for Some Prospective Northeast Asian Power Ties

Transmission Line Component	Length	Voltage	Capacity	Output
1. East Siberia (Bratsk) - North China (Beijing)	2,600 km	600 kVDC	3.0 GW	18 TWh/year
2. Russian Far East (Bureya) - NE China (Harbin)	700 km	400 kVDC	1.0 GW	3 TWh/year
3. South Korea - North Korea	-	345 kVAC	N/A	N/A
4. Russian Far East (Sakhalin) - Japan (Honshu)	1,800 km	600 kVDC	4.0 GW	23 TWh/year
5. Russian Far East (Uchur) to NE China (Shenyang) to South Korea (Seoul)	3,500 km	500 kVDC	3.5 GW	17 TWh/year
6. East Siberia (Buryatia) - Mongolia (Ulan-Bator)	500 km	500 kVAC	0.5 GW	2.5 TWh/year

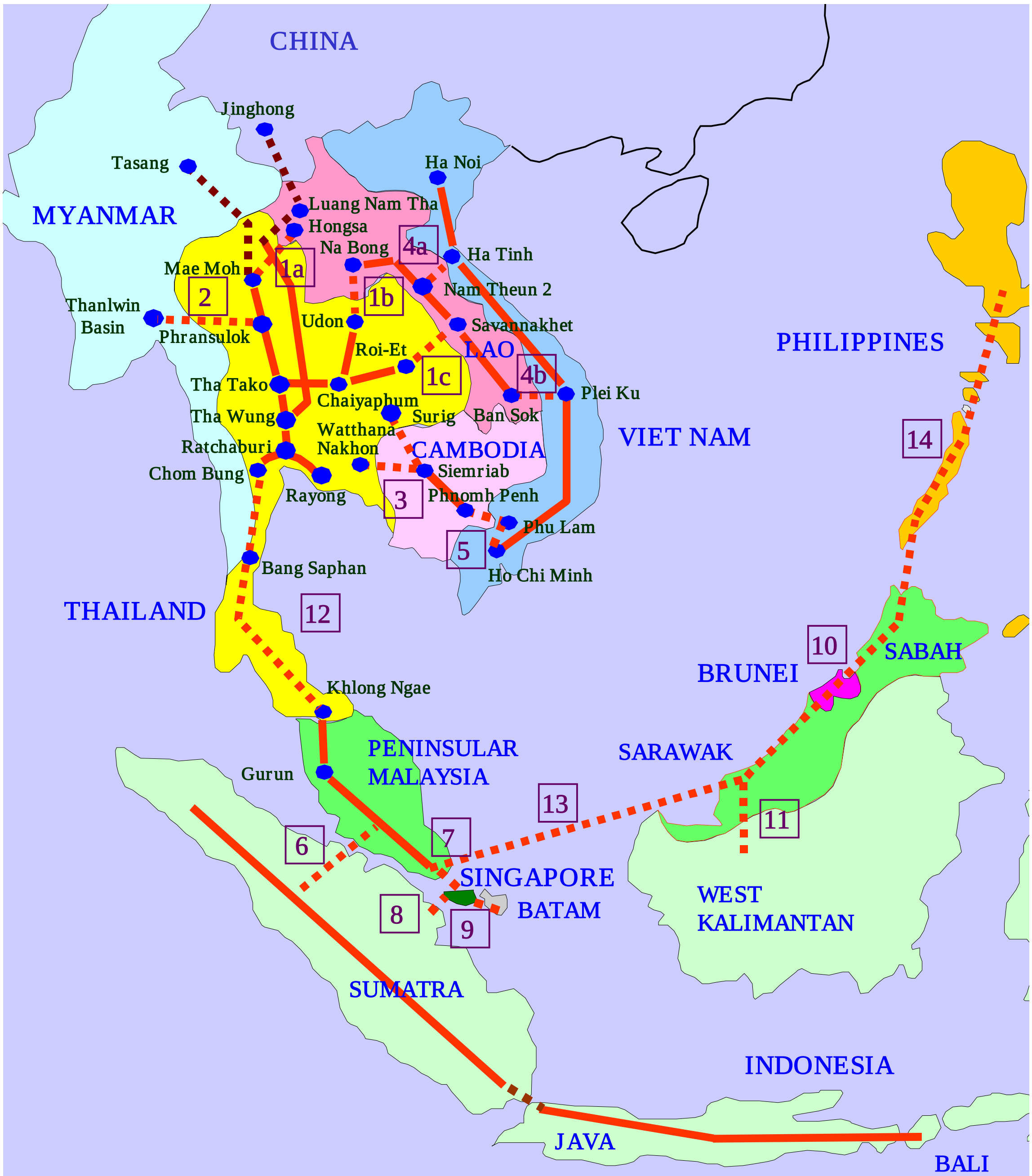
Source: Podkovalnikov (2002).

5 Such proposals have been set forth by experts at several recent conferences, notably workshops on power grid interconnection in Northeast Asia organised by the Nautilus Institute in Beijing (2001), Shenzhen (2002) and Vladivostok (2003). Papers by these experts provided a great deal of source material on Northeast Asia for this report.

POWER GRID PLANS FOR SOUTHEAST ASIA

A plan for power grid interconnections in Southeast Asia has been elaborated under the auspices of the Association of South East Asian Nations (ASEAN). The plan initially included fourteen cross-border projects, supported by national power utilities. These are shown as project numbers 1 through 7 and project numbers 9 through 15 in the figure and table below.

Figure 7 Southeast Asian Power Grid Endorsed by ASEAN Leaders



Source: ASEAN Centre for Energy. Key: Existing lines solid, proposed lines dashed. Project 15 is not shown on map.

The ASEAN Power Grid has been endorsed by the governments of participating economies at the highest level, and specific proposals for the grid have been extensively analysed by a working group of experts. Possibilities for an ASEAN grid first began to be considered by a forum of the Heads of ASEAN Power Utilities and Authorities (HAPUA) that was set up in 1981. Heads of state endorsed a grid in their 1997 declaration on ASEAN Vision 2020 in which they resolved to "establish interconnecting arrangements…for electricity, gas and water….through the ASEAN Power Grid and a Trans-ASEAN Gas Pipeline…" The ASEAN Ministers of Energy Meeting (AMEM) then endorsed a grid for inclusion in the 1998 Hanoi Plan of Action.[6] As one of many measures "to create a stable, prosperous and highly competitive ASEAN Economic Region in which there is a free flow of goods, services and investments…" the Plan of Action called on members to "institute the policy framework and implementation modalities by 2004 for the early realisation of the trans-ASEAN energy networks…" including the Trans-ASEAN Power Grid.[7]

Table 2 Status of Southeast Asian Power Grid Interconnection Projects

Interconnection Project	Type	Capacity	Status, Start
1. Thailand – Lao People's Democratic Republic	HVAC PP	2,015/ 1,578 MW	AP 2008/ 2010
2. Thailand – Myanmar	HVAC PP	1,500 MW	AP 2013
3. Thailand – Cambodia	HVAC EE	300 MW	AP 2016
4. Lao People's Democratic Republic – Viet Nam	HVAC PP	1,887 MW	AP 2007/ 2016
5. Viet Nam – Cambodia	HVAC PP	80/ 120 MW	UC 2003/ 2006
6. Peninsular Malaysia – Sumatra (Indonesia)	HVDC EE	600 MW	UC 2008
7. Peninsular Malaysia – Singapore	HVDC PP	700 MW	Planned 2012
8. Sumatra (Indonesia) – Singapore	HVDC PP	600 MW	Planned 2014
9. Batam (Indonesia) – Singapore	HVAC PP	200/200/200 MW	UC 2014/15/17
10. Sabah/Sarawak (Malaysia) – Brunei Darussalam	HVAC EE	300 MW	Planned 2019
11. Sarawak (Malaysia) – W. Kalimantan (Indonesia)	HVAC EE	300 MW	Planned 2007
12. Thailand – Peninsular Malaysia	undecided	undecided	Speculative
13. Peninsular Malaysia – Sarawak (Malaysia)	undecided	undecided	Speculative
14. Sabah (Malaysia) – Philippines	undecided	undecided	Speculative
15. Lao People's Democratic Republic – Cambodia	undecided	undecided	Speculative

Sources: ASEAN Centre for Energy, ASEAN Interconnection Master Plan Study Working Group (2003).

Note: Projects 1 through 11 were selected by the Master Plan Study Working Group as cost-effective options.

Line Type:	HVAC= high voltage alternating current	**Trade Type:**	PP = power purchase	**Line Status:**	AP = advanced planning
	HVDC= high voltage direct current		EE = energy exchange		UC = under construction

A working group was established in 2000 to undertake an ASEAN Interconnection Master Plan Study (AIMS), completed in 2003. Based upon an optimisation study, eleven potential interconnection projects were selected for potential implementation through 2020. Four of the fourteen links initially proposed, namely those from Thailand to Peninsular Malaysia (number 12 in the table), Peninsular Malaysia to Sarawak in Malaysia (number 13), from Sabah in Malaysia to the Philippines (number 14) and from Laos to Cambodia (number 15), were not selected. The study also selected a 600 MW link from Singapore to Sumatra to be completed in 2014 (number 8).[8]

The power grid master plan is extremely ambitious relative to transmission capacity in place, even though several elements of the plan build upon existing interconnections. The planned 700 MW link between Singapore and Peninsular Malaysia, to be completed by 2010, will add to an existing 500 MW link. The planned interconnections between Thailand and Laos, to add 2,015 MW of transmission capacity in 2008 and another 1,578 MW in 2010, will build upon earlier links of 75 MW in 1972, 45 MW and 214 MW in 1998 and 126 MW in 1999.[9]

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[6] Zamora (2003). ASEAN Heads of State (1997). ASEAN Vision 2020. ASEAN Ministers of Energy Meeting (1998).

[7] ASEAN Heads of State (1998).

[8] Zamora (2003) and HAPUA (2003).

[9] Zamora (2003).

Broadly speaking, the ASEAN power network is to be divided into East and West systems. The East System will include Sarawak and Sabah in Malaysia, Brunei Darussalam, West Kalimantan in Indonesia, and the Philippines. The West System will consist of Laos, Viet Nam, Myanmar, Cambodia, Thailand, Peninsular Malaysia, Sumatra and Batam in Indonesia, and Singapore.[10]

It is worth noting that plans for an ASEAN Power Grid have proceeded in parallel with plans for a Trans-ASEAN Gas Pipeline, shown in Figure 8. A Memorandum of Understanding on the Trans-ASEAN Gas Pipeline was signed by the energy ministers of all ten participating economies in 2002. Elements of the proposed gas pipeline grid, especially in Indonesia, Malaysia, and Brunei Darussalam, appear to follow routes similar to those of the power grid.

Figure 8 Existing and Planned Gas Infrastructure in Southeast Asia

Source: Zamora (2003).

Particular support has been evident for components of the ASEAN Power Grid to be located in the Greater Mekong Subregion that includes Cambodia, Laos, Myanmar, Thailand and Viet Nam as well as Yunnan Province in southern China. A Greater Mekong Subregion transmission study was performed by the Mekong River Commission[11] in 1996, following an energy sector study for the subregion by the Asian Development Bank[12] in 1995. A power trade strategy for the Greater Mekong Subregion was then set forth by the World Bank[13] in 1999. Finally, an Inter-Governmental Agreement (IGA) on Regional Power Trade in the Greater Mekong Subregion was signed by ministers of the subregion's six economies in November 2002. The IGA set up a Regional Power Trade Coordination Committee to establish rules governing regional power trade. It is anticipated that power trade pursuant to the agreement will allow members to "coordinate and cooperate in the planning and operation of their systems to minimize costs while maintaining satisfactory reliability; fully recover their costs and share equitably in the resulting benefits; and promote reliable and economical electric service to the customers of each country." [14]

[10] Heads of ASEAN Power Utilities/ Authorities (2003). Nineteenth Meeting (Surabaya, Indonesia, 2-3 June 2003).

[11] Mekong River Commission (1996).

[12] Asian Development Bank (1995).

[13] World Bank (1999).

[14] Asian Development Bank (2002).

Much of the rationale for enhanced interconnections in the Greater Mekong Subregion centres on the development of hydropower resources in Lao PDR and China's Yunnan province for export to load centres in Thailand and ultimately Viet Nam, as well as the development of hydropower in Myanmar for export to Thailand. A list of prospective hydro projects is shown in the table below.

Table 3 Planned Hydropower Export Projects in the Greater Mekong Subregion

Hydro Project	Year	Origin	Destination	Installed Capacity	Firm Capacity
Nam Theun 2	2008	Lao PDR	Thailand	1,088 MW	937 MW
Nam Ngum 2	2008	Lao PDR	Thailand	615 MW	415 MW
Xe Pian – Xe Namnoy	2010	Lao PDR	Thailand	390 MW	362 MW
Xe Khaman 1	2010	Lao PDR	Thailand	468 MW	408 MW
Tasang	2012	Myanmar	Thailand	3,600 MW	3,000 MW
Jinghong	2013	China	Thailand	1,500 MW	863 MW
Nuozhadu	2014	China	Thailand	5,500 MW	2,393 MW
Sambor CPEC	2019	Cambodia	Viet Nam	465 MW	347 MW

Source: Doorman and others (2004).

Several of the proposed interconnections in the Greater Mekong Region correspond to those between Thailand and Lao PDR in the ASEAN vision (row 1 in Table 2), all with a 500 kV rating. Within the Lao PDR, a 940 MW line, to be completed in 2008, would run to Savannakhet from the Nam Theun 2 hydro plant, while an 858 MW line, to be finished in 2010, would run to Savannakhet from Bon Sok, fed by hydropower from Xe Haman 1, He Pian and Xe Namnoy. These two lines would join into a 1,798 MW line from Savannakhet to Roi Et in Thailand, to be completed in 2008, which would link to a line of the same capacity from Roi Et and Chaiyaphum. Meanwhile, a 1,075 MW line would be built by 2009 from Na Bon in Lao PDR to Udon Thani in Thailand, fed by the Nam Ngum 2 and 3 hydro plants and linking to a line of the same capacity between Udon Thani and Chaiyaphum. The 1,798 MW lines and the 1,075 MW lines would then join into a previously built 2,873 MW line from Chaiyaphum to Tha Tako. Meanwhile, a 720 MW line would be built by 2009 from the Hongsa lignite-fuelled plant in Lao PDR to Mae Moh in northern Thailand.[15]

Several proposed Greater Mekong power interconnections also correspond to components of the ASEAN vision between Lao PDR and Viet Nam (row 4 in Table 2). A 636 MW, 500 kV line, to be finished by 2008, would extend to Ha Tinh in north-central Viet Nam from Nam Theun 2 in Lao PDR, fed by power from the Nam Theun 1 and 3 hydro plants. Meanwhile, a 1,151 MW, 500 kV line, to be built by 2012, would run to Pleiku in south-central Viet Nam from Ban Sok in Lao PDR, fed by hydropower from the Xe Khaman 3, Nam Kong 1 and Sekong 4 plants. A lower-voltage 100 MW line, to be completed by 2007 or 2008, would run from the Nam Mo hydro plant in Lao PDR to Ban La in Viet Nam. Together, the capacity of these lines sums to the 1,887 MW anticipated in the ASEAN plan for new connections between Lao PDR and Viet Nam.

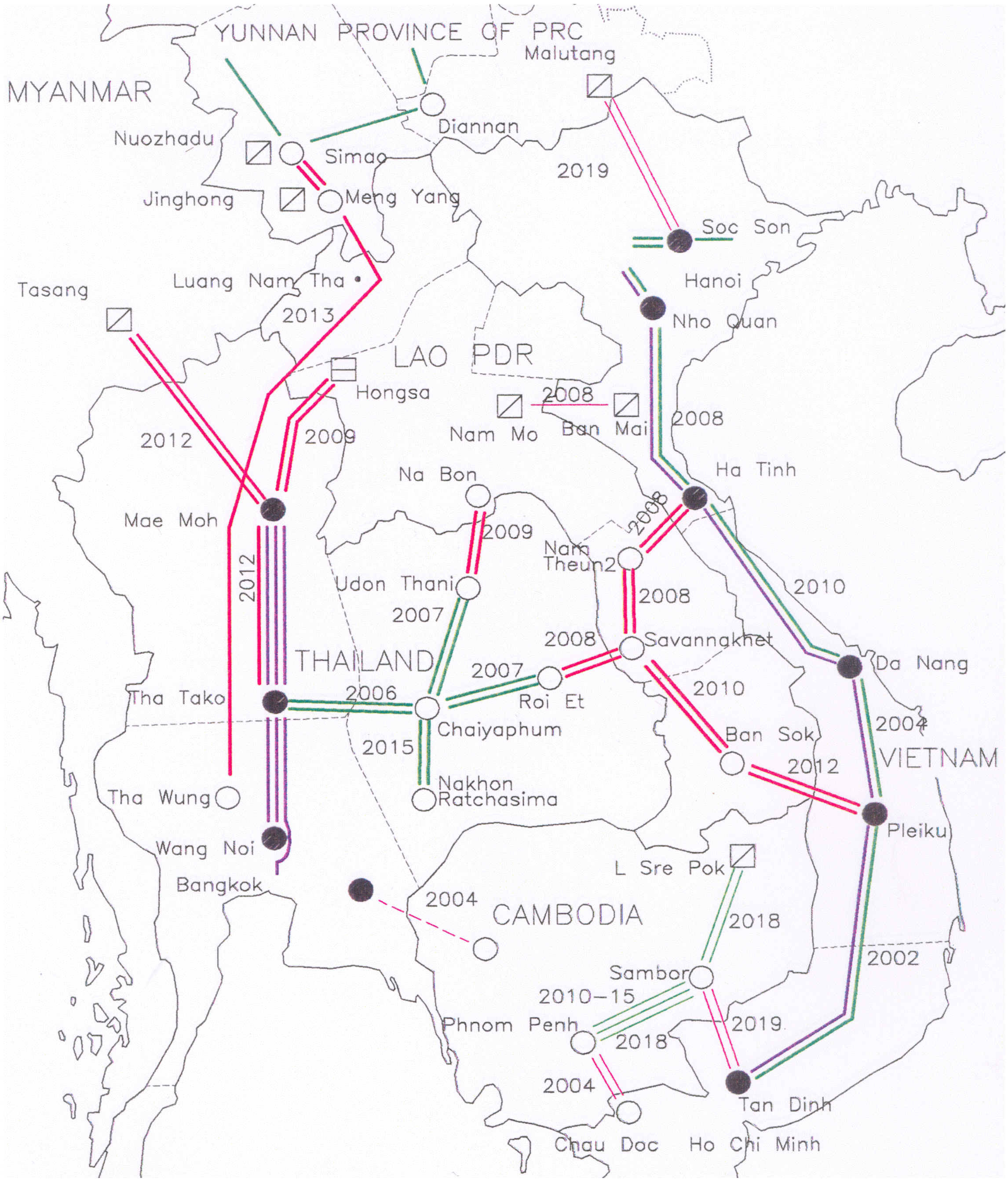
Another major power link proposed for the Greater Mekong is the one contained in the ASEAN plan between Myanmar and Thailand (row 2 in Table 2). A 1,500 MW transmission line rated at 500 kV would be built from Tasang in Myanmar to Mae Moh in northern Thailand by 2012, together with reinforcements to Thailand's power grid running south toward Bangkok.

A couple of smaller proposed interconnections in the ASEAN plan apparently have not yet been incorporated into proposals for the Greater Mekong. One of these is the 300 MW, 230 kV link proposed between Cambodia and Thailand (row 3 in Table 2), to run from Surin to Tiem Reap to Struengtreng and Battabang by 2016. The other is the 200 MW, 220 kV link proposed between Cambodia and Viet Nam (row 5 in Table 2), to run from Takeo to Chaudoc by 2006.

[15] Doorman and others (2004). The 940 MW and 1,075 MW lines sum to the 2,015 MW of capacity in the ASEAN plan to be finished by around 2008, while the 858 MW and 720 MW lines sum to the 1,578 MW to be finished by 2010.

Conversely, a few proposed new power links in the Greater Mekong Subregion go beyond what as been proposed in the broader ASEAN context. The 500 kV lines in northeastern Thailand would be reinforced by 2015 to accommodate greater power flows southward. A 230 kV line would be built by 2019 from Lower Sre Pok to Sambor and Phnom Penh in Cambodia, as well as from Sambor to Tan Dinh in Viet Nam. A 500 kV HVDC transmission line would link the Jinghong and Nuozhadu hydro projects in the Yunnan province of China to Thailand by 2013, while a 230 kV line would link the Malutang hydro plant in Yunnan with Viet Nam by 2019.

Figure 9 Extended Power Cooperation Scenario for Greater Mekong Subregion



Source: Doorman and others (2004). Note: Existing substations are shown as filled circles, planned substations as empty circles. Hydro plants are shown as squares with a diagonal slash, fossil-fuelled plants as squares with a horizontal slash.

RELIABILITY BENEFITS OF POWER GRID ENHANCEMENT

INTRODUCTION

Well-functioning electric power grids are essential to the reliable provision of electricity to most consumers. While it is possible to generate electricity independently of power grids, off-grid power is generally much less reliable or much more expensive than grid-connected power. To provide power reliably without a grid requires generating technologies that are less efficient, less developed, or more intermittent than the large-scale power plants that produce the bulk of power consumed today. For example, small diesel generators have relatively low operating efficiencies and high fuel costs, building-scale fuel cells are still at an early stage of development and have relatively high capital costs, and photovoltaic modules and wind turbines require diesel or other backup in order to provide power at times when the sun is not shining or the wind is not blowing.

Yet power grids may sometimes malfunction, leading to costly and hazardous blackouts. The huge blackouts that occurred in North America and Europe in the summer of 2003, leaving tens of millions of people without power, were the largest in history but far from the first. The immediate causes of such blackouts may be operational in nature, with slow reactions to a failure in one part of an interconnected system leading to rapidly cascading failures in much of the rest of the system. Power grids may thus be made more reliable through improved procedures that speed reactions to transmission line problems and forestall breakdowns in the transmission system as a whole.

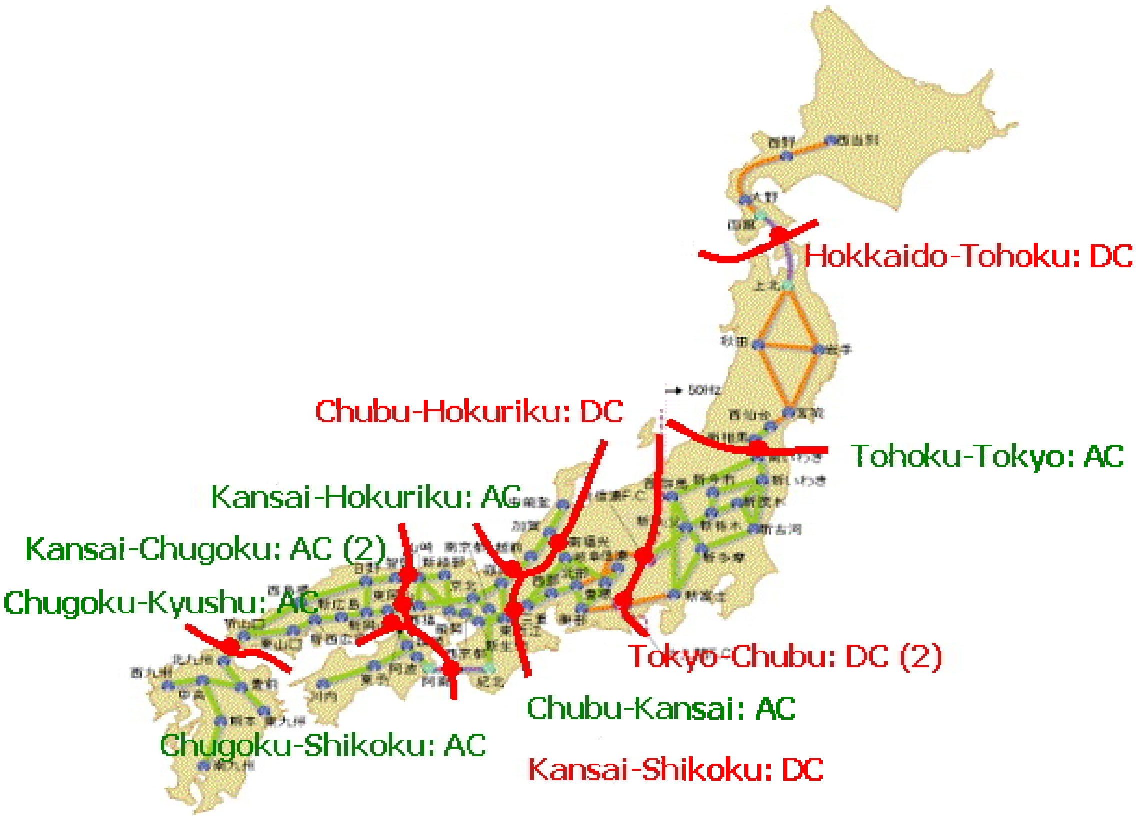
But the underlying cause of blackouts may be systematic underinvestment in transmission grids as demand for power grows and trading for power becomes more widespread. In Japan and North America, demand for power has indeed outpaced expansion of the transmission grid for many years. Moreover, regulatory reforms providing for open access to transmission grids by competing generators and suppliers mean that generators seek to sell their power and suppliers seek to obtain their power over greater distances, even as available transmission capacity becomes constrained. Enhancements to power grids, by relieving congestion, increase the available paths over which power can flow in the event of a failure on any one transmission line, thereby reducing the chance that an isolated failure may escalate into a systemic one. Just as important, replacement or upgrading of ageing transmission facilities reduces the chance that any line will fail in the first place.

Further, it is worth considering an important dimension of electric system reliability that relates to the diversity of electric generating capacity. If certain areas rely to a great extent on any single type of electric power, they may be vulnerable to a situation in which that type of power, for any reason, becomes unavailable. A recent instance occurred Japan with a regulatory requirement to take all or most nuclear power plants in the Tokyo area out of service during 2002 and 2003. Because such plants normally provide nearly half of the area's electricity, their absence could easily have led to a power failure for its forty million residents if alternative sources were not available. A future example might conceivably occur if global warming were to accelerate at an unanticipated pace and regulators in some places decided to restrict the continued use of coal-fired power plants. In such an instance, the availability of extra transmission capacity to bring in power from other types of power plants in neighbouring areas could be essential to maintaining reliable service.

RELIABILITY BENEFITS OF POWER GRID ENHANCEMENTS IN JAPAN

In each of Japan's ten electricity service areas, the dominant utility has developed a power grid that is designed to supply electricity reliably without the need for assistance from neighbouring areas. Thus, transmission links within each service area are extensive and tightly networked, so that failure on any single line is easily compensated by power flows through remaining lines. With very substantial investment in transmission facilities over the years, as well as ample reserve margins of electric generating capacity over peak demand, the reliability electricity service in Japan has indeed been very high. Service interruptions have recently averaged just ten minutes or so per customer per year, ranging as low as a third that level in 1987 and up to triple that level in 1993.[16]

Figure 10 Major Transmission Links Between Service Areas in Japan in 2003



Source: Central Research Institute of the Electric Power Industry, Japan

But power interconnections are far less developed between Japan's electric service areas than within them. Thus, an issue has arisen with respect to what might happen to the reliability of power supply in Japan when a particular class of generating capacity has to be taken out of service. In August 2002, the Tokyo Electric Power Company (TEPCO) was required by the Japanese government to take all of its nuclear power plants out of service since the utility had failed to report technical safety violations at some of the plants as required by law. Although subsequent safety inspections revealed that none of the violations presented an actual threat to public safety, continuing public distrust meant that nearly all of Tokyo's nuclear plants remained out of service through the summer of 2003 and beyond. Since summer is when Tokyo's power demand peaks, and since TEPCO relied on nuclear power for 29 percent of its generating capacity and 47 percent of its electricity generation in 2001[17], there were real concerns that power demand might not be met.

Normally, TEPCO would have had roughly 72 GW of generating capacity available to meet Tokyo's needs during the summer of 2003, including 60 GW of its own capacity, 8 GW owned by Japan's Electric Power Development Corporation (EPDC) and other generators in its area, and 4 GW from companies outside of its area. But with 13 GW of nuclear capacity remaining out of service (though about 4 GW of nuclear capacity had already been allowed to resume service), and with 4 GW of thermal power plants out of service for scheduled maintenance, the actual amount of generating capacity on which TEPCO could rely that summer was only around 55 GW. By

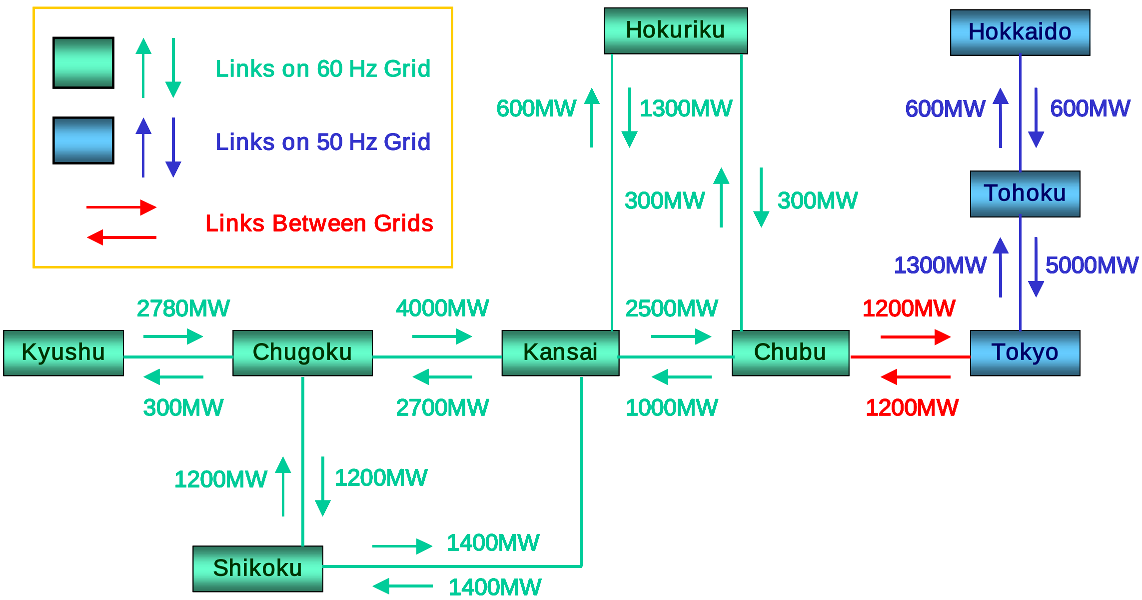
[16] Kurihara (1999), (2003).

[17] TEPCO (2004). Tables of Powerplant Generating Capacity and Powerplant Net Generation.

comparison, the utility projected that peak demand would be around 61 GW if the weather were normal and 64 GW if the summer were hot. Hence, it had to plan for a possible 9 GW shortfall.

TEPCO's plans for filling the gap between available capacity and possible peak summer demand included a variety of supply-side and demand-side measures. On the supply side, the utility anticipated that it could obtain 2,190 MW by restarting thermal plants that had been shut down due to their relative inefficiency and high cost, 760 MW by accelerating the testing and start-up of new plants, 700 MW by rescheduling thermal plant repairs, and 1,660 MW through extra purchases from neighbours. Somewhat more alarmingly, the utility hoped to obtain 3,200 MW if necessary through emergency supply measures such as power drawn from the trial operation of thermal plants and requests for neighbouring utilities to raise the output of thermal plants above their design limits. On the demand side, it hoped to fill 1,300 MW of its capacity gap through load-adjustment contracts whereby customers agreed to have their power cut off at times of system peak load.[18]

Figure 11 Total Transmission Capacity Between Japan's Electric Service Areas in 2003



Source: Central Research Institute of the Electric Power Industry, Japan. Tokyo-Chubu figures are as of September 2005. Figure shows to operational capacity of interconnections under frequency, stability and voltage constraints.

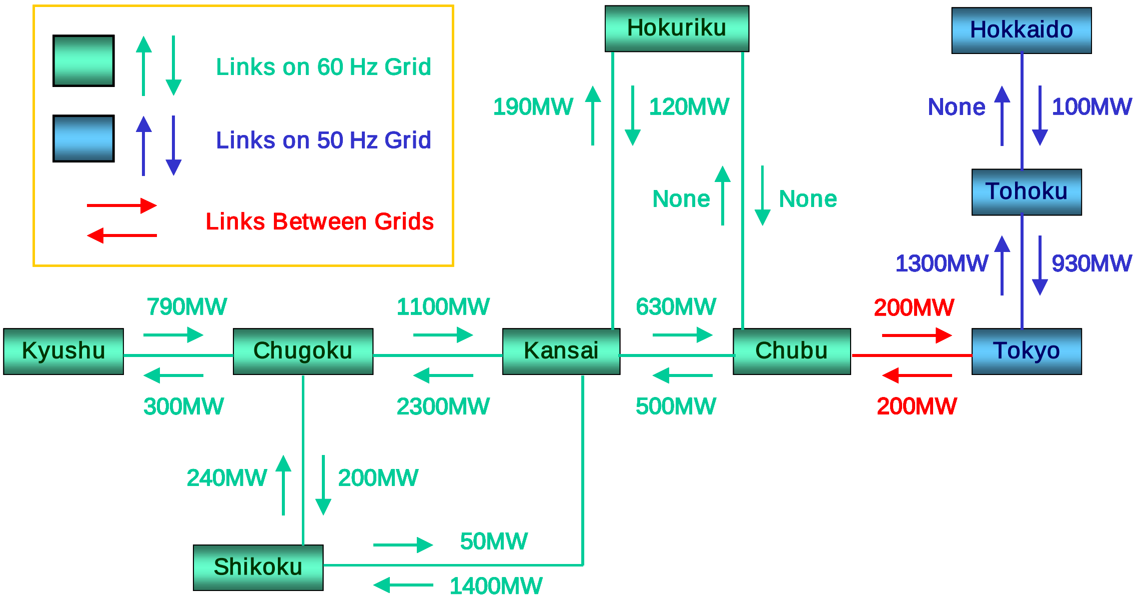
In fact, the overall transmission capacity to transfer power into Tokyo from neighbouring areas was quite substantial during the summer of 2003. Approximately 5,000 MW of power could have been transferred over transmission lines from Tohoku to the north, assuming the availability of surplus generating capacity. Another 300 MW of power could have been transferred from Chubu to the west, utilising DC links between the 50Hz and 60Hz power grids. (This amount will increase to 1,200 MW in September 2005, with the completion of new transmission lines.) So theoretically, as much as 5,300 MW in all might have been sent to Tokyo to make up for any capacity shortfalls.[19]

Whether neighbouring areas would normally have had this much surplus power to send to Tokyo is more problematical, since they experience peak summer loads at about the same time. But in the event, the summer of 2003 proved to be cooler than normal, with a peak load in Tokyo of just 57 GW. So plenty of power was available, the transmission system suffered little stress, and the reliability of service was not impaired. Yet on a hotter summer, with less capacity available for interregional power transfers and less surplus generating capacity available for transmission over the grid, an area-wide nuclear plant outage might have had serious reliability consequences.

[18] TEPCO (2003).

[19] Kurihara (2003).

Figure 12 Available Transmission Capacity for Long-Term, Firm Power Transactions Between Japan's Electric Service Areas from 2003 through 2013



Source: Central Research Institute of the Electric Power Industry, Japan. Tokyo-Chubu figures are as of September 2005.

Indeed, available transmission capacity for long-term, firm power transactions between Japan's electric service areas, as shown in Figure 12, is far less than the total transmission capacity between these areas, as shown in Figure 11. Available capacity equals overall capacity less capacity already reserved for long-term transactions less a reliability margin for emergency frequency operation. The reliability margin is often substantial since interconnections between neighbouring areas are limited in number, requiring the system to depend on specific interconnections in the event of emergency. Available firm transmission capacity into Tokyo will total 1,130 MW as of September 2005 (930 MW from Tohoku and 200 MW from Chubu), about a fifth of the overall transmission capacity of 6,200 MW (5,000 MW from Tohoku and 1,200 MW from Chubu). So the ability of adjacent areas to make up for power shortfalls in Tokyo on an ongoing basis would be quite limited, even if adjacent areas had as much surplus generating capacity as the capital area required.

Available firm transmission capacity is far below total transmission capacity elsewhere in Japan as well. In Chubu, which relied on nuclear power for 9 percent of its electricity generation in 2002, available firm incoming transmission capacity is just 830 MW (200 MW from Tokyo and 630 MW from Kansai), roughly a fifth the total capacity of 4,000 MW (1,200 MW from Tokyo, 2,500 MW from Kansai, and 300 MW from Hokuriku). Since Chubu has 3,617 MW of nuclear generating capacity, the ability to replace such capacity with imports if it were temporarily called out of service would therefore be doubtful. In Kansai, which relied on nuclear power for 65 percent of its electricity generation in 2002, available firm incoming transmission capacity is only 1,770 MW (500 MW from Chubu, 120 MW from Hokuriku, 1,100 MW from Chugoku, and 50 MW from Shikoku), less than a quarter of total transmission capacity of 7,700 MW (1,000 MW from Chubu, 1,300 MW from Hokuriku, 4,000 MW from Chugoku, and 1,400 MW from Shikoku). Since Kansai has 9,768 MW of nuclear capacity, it could not all be replaced by imports if called out of service.[20]

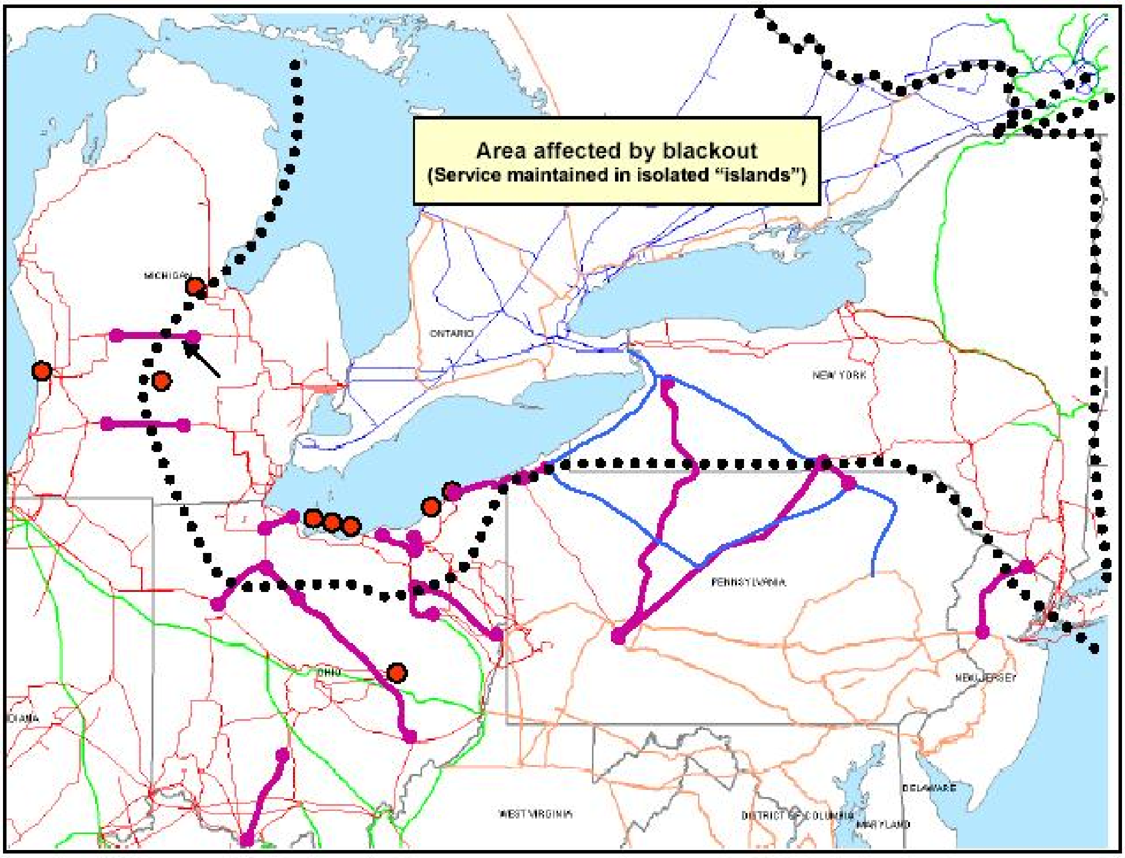
Such scenarios may fairly be described as unlikely, but since Tokyo's nuclear power plants were in fact called out of service in 2002 and most of them remained so as demand peaked during the summer of 2003, they cannot be ruled out. In this light, it may make sense for Japan's electricity producers to consider the available options for expanding transmission capacity across different service areas. In particular, it may be useful to compare the marginal benefit of expenditures to further elaborate transmission grids within service areas, which are already highly developed, with that of expenditures to substantially expand transmission links across service areas, which are not.

[20] Kurihara (2003). Japan Electric Power Information Center (2004), page 44.

RELIABILITY BENEFITS OF POWER GRID ENHANCEMENTS IN NORTH AMERICA

The power failure that rocked North America in the summer of 2003, plunging the abodes of some fifty million people into darkness, has been billed as the largest in history. It affected a sixth of the combined populations of Canada and the United States, including the inhabitants of each of their largest cities, Toronto and New York. It took some 34,000 miles of transmission lines out of service, or more than a fifth of the transmission network in the United States, along with more than 531 generating units with 61 gigawatts of capacity.[21] But beyond those basic facts, there is some disagreement over the extent to which the blackout was due to operational failures on the Eastern Interconnection and the extent to which it was due to long-term underinvestment in transmission.

Figure 13 The Great North American Blackout of August 2003



Source: United States Department of Energy

To shed light on this issue, a brief review of the blackout chronology described by the U.S.-Canada Power System Outage Task Force may be helpful:

- Phase 1: A Normal Afternoon Degrades: The Midwest Independent System Operator's "state estimator" software for "single contingency" assessments of grid reliability (with the largest single facility out of service) malfunctions for most of the period from 12:15 to 16:04 Eastern Daylight Time, two minutes before the blackout cascade. FirstEnergy's Eastlake 5 plant, a major source of reactive power in Ohio, trips out of service at 13:31 EDT, reducing grid's ability to respond to undervoltage.
- Phase 2: FE's Computer Failures: First Energy loses the visual and auditory alarms that would alert its control room operators to problems at 14:14 EDT, and all related computer functions collapse by 14:54 EDT, but operators remain unaware until 15:59 that their computer systems are not operating properly.

[21] Sauer (2004). U.S.-Canada Power System Outage Task Force (2003), page 63.

- Phase 3: Three FE 345-kV Transmission Line Failures and Many Phone Calls: Three separate 345 kV lines owned by FirstEnergy fail between 15:05:41 and 15:41:35 EDT due to contact with overgrown trees along their rights-of-way, even though power flows are at or below each line's emergency operational rating. Repeated phone calls from Midwest ISO, PJM, and AEP indicate potentially serious problems but are basically ignored by First Energy until at least 15:42.
- Phase 4: 138-kV Transmission System Collapse in Northern Ohio: Virtually all 138-kV transmission lines in northern Ohio trip out of service between 15:39 and 16:08.
- Phase 5: 345-kV Transmission System Cascade in Northern Ohio and South-Central Michigan: Sammis-Star 345-kV line trips out of service at 16:05:57 as protective relays detect low apparent impedance (low voltage divided by high current). Two other 345-kV lines leave service about 3 minutes later, causing major power swings (current oscillations) in New York, Michigan and Ontario. 937 MW of power lost.
- Phase 6: The Full Cascade: In less than three minutes, from 16:10:36 to 16:13 EDT, thousands of events on the grid plunge Ontario and US Northeast into darkness.
- Phase 7: Several Electrical Islands Formed in Northeast US and Canada: In about a minute, from 16:10:46 to 16:12, most of New England and western New York state, as well as Canada's Maritime Provinces, split from neighbouring parts of the grid and stay in operation due to good local balance between generation and load.[22]

At least with respect to the events that initiated the blackout (phases 1 through 4), its causes appear to be mainly operational. The U.S.-Canada Task Force noted that one key cause of the blackout was that FirstEnergy "failed to manage adequately tree growth in its transmission rights-of-way." The Task Force also noted procedural violations of reliability standards established by the North American Electric Reliability Council (NERC). First Energy "did not notify other systems of an impending system emergency," the Midwest ISO "did not notify other reliability coordinators of potential problems," and FirstEnergy's "operator training was inadequate for maintaining reliable operation." But the operational failures did not relate just to deficient procedures or training. They also related in part to weaknesses in monitoring tools and diagnostic equipment, which would point to a need to upgrade such tools and equipment and make them more widely available.[23]

A major cause of the blackout highlighted by the Task Force is "inadequate situational awareness." This occurred in part because FirstEnergy (FE) "did not have additional monitoring tools for high-level visualization of the status of their transmission system" that would have been able "to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems" in phase 2. If operators had had such additional monitoring tools, they might have responded promptly to the mounting evidence of problems in phase 3 instead of assuming the problems did not exist, and the blackout might have been avoided.

Another major cause of the blackout identified by the Task Force is "failure of the interconnected grid's reliability organizations to provide effective diagnostic support." The Task force notes that the Midwest ISO violated NERC reliability standards in that it "did not have adequate monitoring capability." In particular, "MISO's "reliability coordinators were using non-real-time data" to support the real-time monitoring of flowgates ("groupings of transmission lines and equipment that sometimes have less transfer capability than desired"). "This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions." Furthermore, "MISO lacked an effective means of identifying the location and significance of transmission line breaker operations reported by their Energy Management System (EMS). Such information would have enabled MISO operators to become aware earlier of important line outages" during phases 1 and 3, again allowing more time for remedial actions.[24]

[22] U.S. - Canada Power System Outage Task Force (2003), pages 21-61.

[23] Ibid., pages 23-26.

[24] Ibid., pages 23, 26-7, 36, 39.

In phase 1, the malfunctioning of MISO's state estimator for the grid was largely due to the fact that outages on the Bloomington-Denois Creek 230-kV line (around 12:15) and the Stuart-Atlanta 345-kV line (around 14:02) were not automatically registered by MISO's diagnostic equipment. MISO's electrical system model therefore assumed these lines were in service, whereas measured system flows reflected that fact that they were not. Discrepancies between measured and modelled flows prevented the state estimator from solving correctly for most of the four-hour period starting around 12:15. Consequently, the Task Force finds, "MISO could not fully identify FE's precarious system conditions until 16:04 EDT," two minutes before the blackout cascaded. Notably, when the Harding-Chamberlin 345-kV line tripped at 15:05, beginning phase 3 of the blackout, "the state estimator did not produce results and could not predict an overload if the Hanna-Juniper 345-kV line were to fail" as it did at 15:32, causing the Star-South Canton 345-kV line to trip at 15:41. [25]

With respect to the blackout cascade (phases 5 through 7), the scope of the blackout appears to be mainly related to underinvestment in transmission. This is perhaps most clearly indicated by the explanation in the Task Force report about what stopped the blackout from cascading further. The report states that "Higher voltage lines and more densely networked lines, such as the 500-kV system in PJM and the 765-kV system in AEP, are better able to absorb voltage and current swings and thus serve as a barrier to the spreading of a cascade." In contrast, the report notes, "the cascade progressed into western Ohio and then northward through Michigan through the areas that had the fewest transmission lines. Because there were fewer lines, each line absorbed more of the power and voltage surges and was more vulnerable to tripping."[26] This would point to a need to upgrade the strength and voltage profile of the transmission grid through investment in new lines.

To summarise, three main conclusions can be drawn from the chronology of blackout events. First, investment in improved monitoring and diagnostic equipment would reduce the likelihood of a blackout getting started. Second, investment in new transmission lines in areas where the grid is heavily loaded would help stop a blackout from cascading, reducing its likely geographic scope. Third, the value of investment in grid upgrades, in terms of reliability, will be greatly enhanced by improvements in operational procedures, communications protocols and operator training.

With respect to the second conclusion, regarding the linkage between reliability and investment in new transmission lines, it may reasonably be argued that a deficiency of investment in recent years has made the North American power grid more vulnerable to disruption. As shown in Figure 14, annual investment in the United States transmission grid declined from around US$6 billion in 1975 to around US$3 billion in 2000, falling by more than $100 million each year over the course of a quarter of a century, even as demand for electricity steadily expanded. With less and less grid capacity per kilowatt-hour of electricity supplied, it stands to reason that transmission lines have become increasingly loaded over time, raising the likelihood of periodic voltage deficiencies and making many lines less able to withstand grid instabilities to prevent a blackout from cascading.

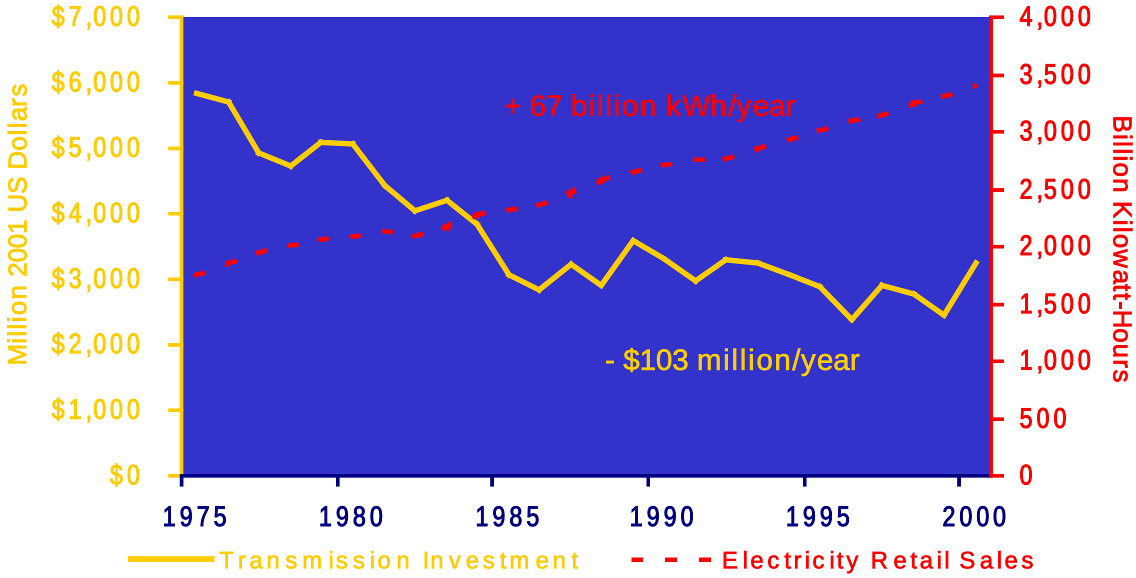
Certainly, it could be observed that the North American transmission grid was coming under growing stress over the several years that preceded the blackout. With increasing frequency, transmission lines became so heavily loaded that system operators had to request that loads on the

[25] *Ibid.*, pages 24, 27-28, 36, 39. Operational factors also contributed significantly to the state estimator's failure. When the true status of Bloomington-Denois Creek line was discovered, allowing the state estimator to solve correctly by 13:07, the system operator forgot to reenable the automatic trigger that normally runs the state estimator every five minutes and left for lunch. By the time the automatic trigger was reenabled at 14:40, the failure of Stuart-Atlanta at 14:02, which was unknown to the ISO, again prevented the state estimator from solving correctly. While the true status of Stuart-Atlanta was discovered at 15:29 and the state estimator was manually operated to reach a successful solution by 15:41, it was not back under full automatic operation until 16:04, about two minutes before the start of the cascade.

[26] U.S - Canada Power System Outage Task Force (2003), page 51. There were also operational reasons why certain areas were inoculated against the cascading blackout. The report notes on page 61 that "within the Midwest, there were relatively low reserves of reactive power, so as voltage levels declined many generators in the affected area were operating at maximum reactive power output before the blackout. This left the system little slack to deal with the low voltage conditions…. In contrast, in the northeast – particularly PJM, New York, and ISO-New England – operators were anticipating high power demands on the afternoon of August 14, and had already set up the system to maintain higher voltage levels…. Thus, when the voltage and frequency swings began, these systems had reactive power already or readily available to help buffer their areas against a voltage collapse without widespread generation trips."

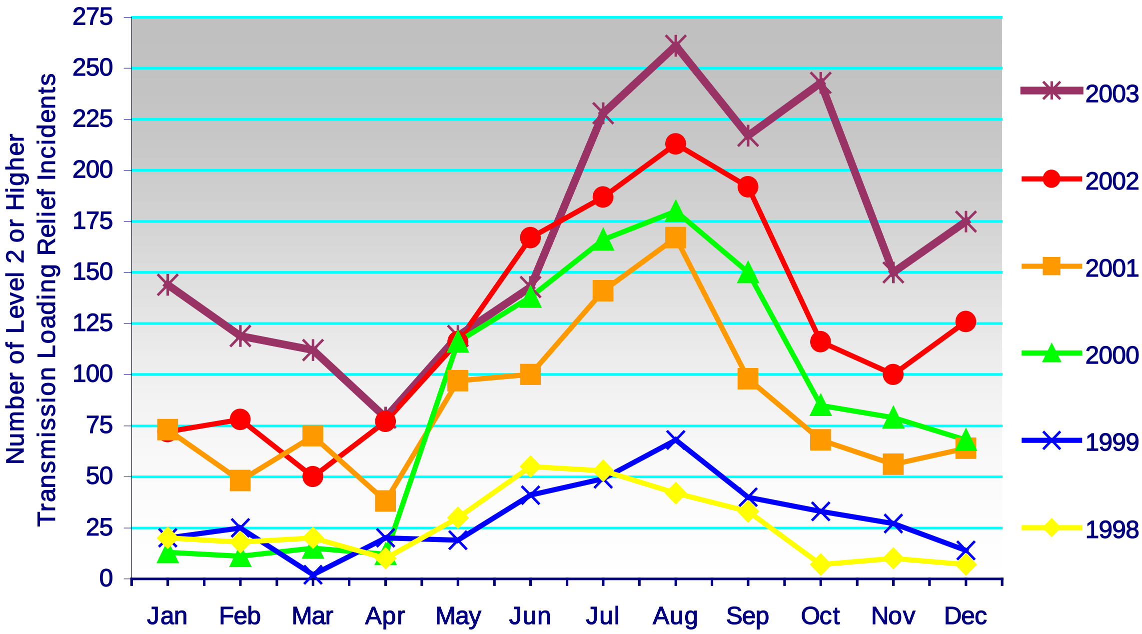
lines be reduced. In the United States, as shown in Figure 15, the peak monthly number of "level 2 or higher" calls for transmission loading relief (TLRs), which occur when the grid is heavily loaded, has grown nearly five-fold from 55 in the summer of 1998 to 261 in the summer of 2003. The annual number of "level 5 or higher" TLRs, which require a curtailment of firm transmission service, is smaller but has grown even more dramatically, from just 1 in 1999 to 28 in 2001 and 68 in 2003.[27]

Figure 14 Declining Transmission Investment and Growing Electricity Demand in the United States, 1975-2000



Source: Edison Electric Institute, United States Energy Information Administration

Figure 15 Transmission Loading Relief Incidents in the United States, 1998-2003



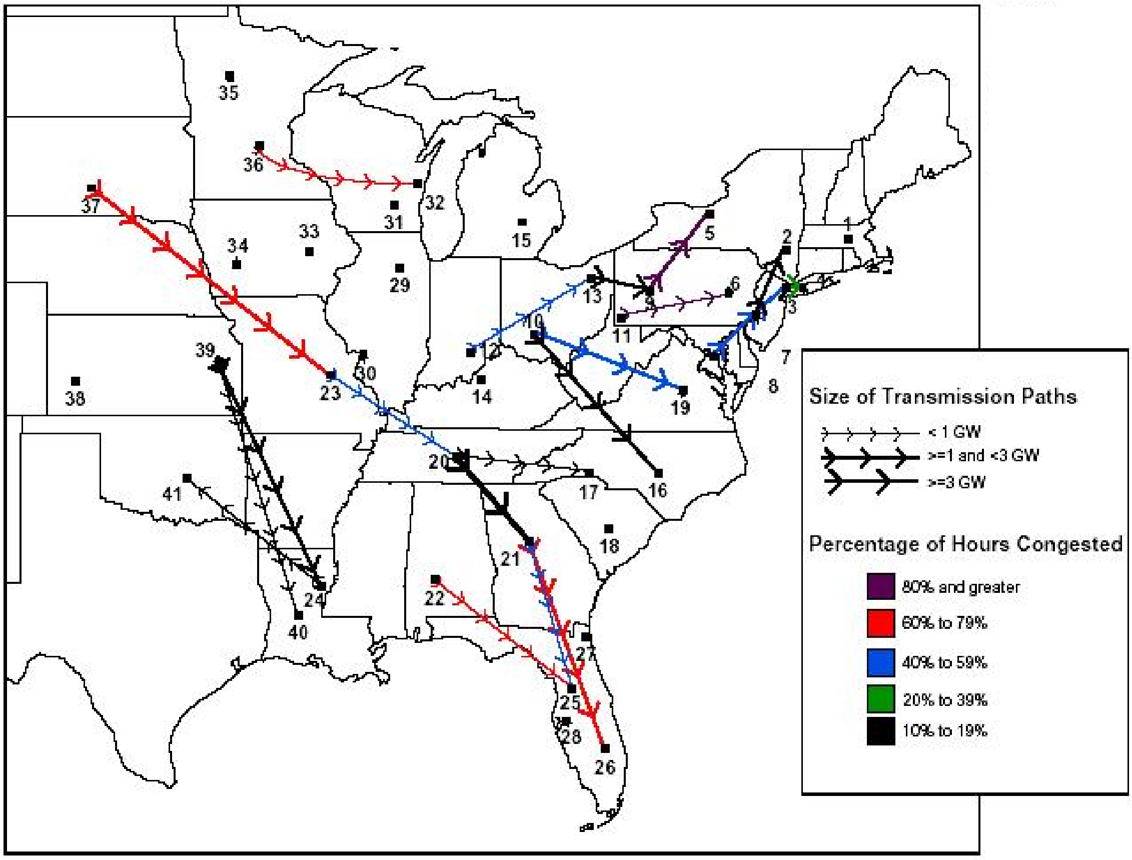
Source: North American Electric Reliability Council

On the Eastern Interconnection, several major power interconnections have lately been congested a great deal of the time, as shown in Figure 16. For example, a 3 GW interconnection between western Pennsylvania and New York was congested more than 80 percent of the time in

[27] North American Electric Reliability Council (2004). Huntoon and Metzner (2003).

2002. A 3 GW transmission link from South Dakota to Missouri was congested more than 60 percent of the time. A 3 GW transmission line between Ohio and Virginia was congested more than 40 percent of the time. As noted in the National Transmission Grid Study, "out of a total of 186 transmission paths modelled in the East, 50 are used to their maximum capacity at some point during the year, and 21 paths are congested during more than 10 percent of the hours of the year."[28]

Figure 16 Transmission Line Congestion in the Eastern United States in 2002



Source: United States Department of Energy, National Grid Study (2002).

The Western Interconnection was also heavily loaded much of the time, with a clear pattern of congestion seen for power moving into California, as seen in Figure 17. Of the 106 transmission paths modelled by the National Grid Study in the West, "37 are congested at some point during the year, half of these are congested less than 10 percent of the time, and no path is congested more than 60 percent of the hours during the year." Much of the power flow is seasonal, with the Pacific Northwest sending excess hydropower to California and other states during the spring and summer and buying power from those other states during the winter through large direct current links.[29]

While investment in transmission grid is costly, so are the consequences of unreliable service. For example, a blackout in the West in August 1996, which interrupted power to 7.5 million customers, cost some $2 billion in economic losses. One of the costliest components of unreliable service is the cumulative impact of small disruptions, particularly for high-technology industries like semiconductors, fiber optics, and others using continuous processes. The Electric Power Research Institute has estimated the cost of power disturbances to industry at $119 billion to $188 billion.[30]

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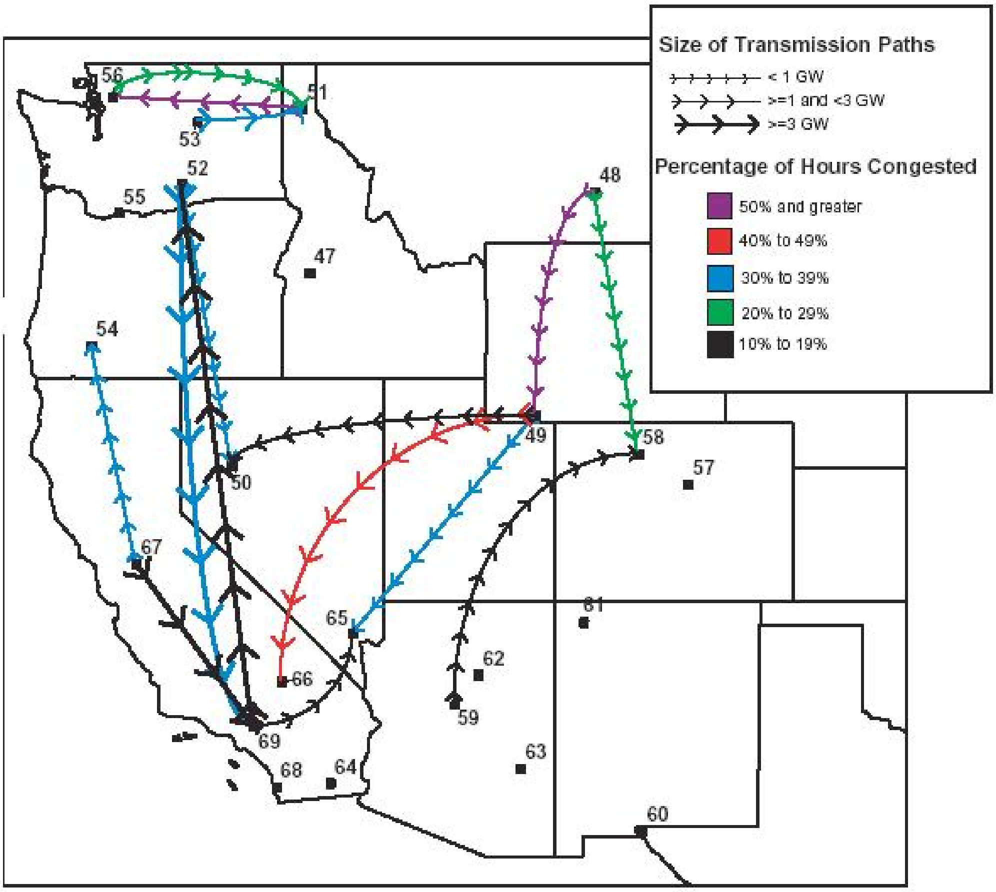
28 US Department of Energy (2002), pages 11-12.

29 Ibid., pages 15-16.

30 Ibid., page 20. Carrier and Skeer (2002). Electric Power Research Institute (2001). Hauer and Dagle (1999).

Figure 17 Transmission Line Congestion in the Western United States in 2002



Source: United States Department of Energy, National Grid Study (2002).

RELIABILITY IMPACTS OF POWER INTERCONNECTIONS IN NORTHEAST ASIA

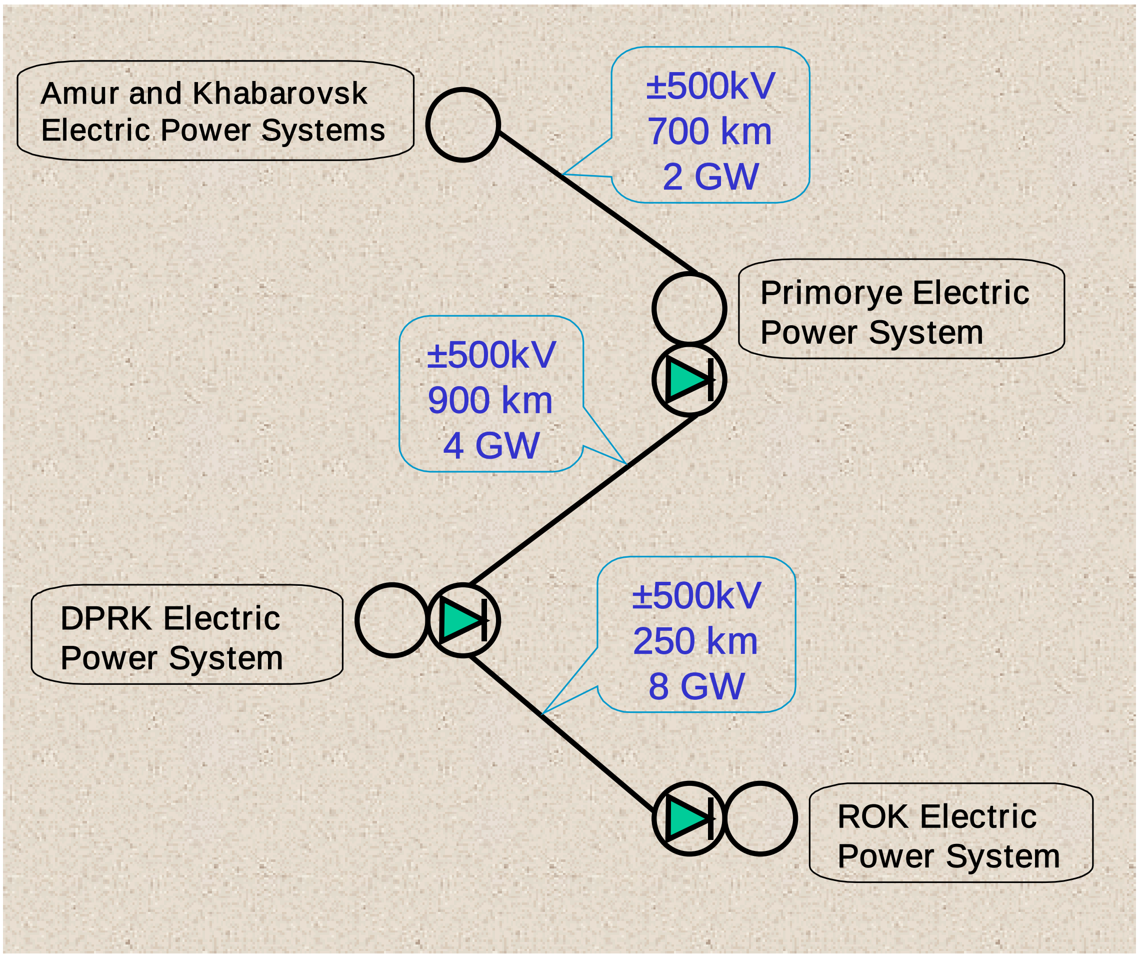
Since most proposals for power grid interconnections in Northeast Asia are quite recent and are in a state of flux, the reliability impacts of new power grid links have not been evaluated in any comprehensive fashion for the region as a whole. However, a few studies have examined the likely reliability impacts of a particular interconnection or group of interconnections in the region.

One study focused on potential power links between the Russian Far East (RFE), North Korea (Democratic People's Republic of Korea – DPRK), and South Korea (Republic of Korea – ROK). The configuration evaluated is shown in Figure 18, with a 2 GW line linking Amur and Khabarovsk with Primorye in the RFE, a 4 GW line linking the RFE with the DPRK, and an 8 GW line linking the DPRK with the ROK. A reliability study of this interconnection was performed using the Russian YANTAR model. With the three power systems of RFE, DPRK and ROK operating independently, the model found that the probability of system failure was about 343 millionths. With the power systems operating together through the interconnections, the model found that the probability of system failure would decline to about 71 millionths. Thus, an interconnection between the three economies could cut the incidence of power outages by a roughly factor of five.

The study found that reliability would improve even though generating capacity would decline by 8 GW. The combined system would need less reserve capacity because lower reserves in each participating power system would be compensated by the ability to receive backup power from the other participating systems. However, reserve margins would probably increase in RFE, where power plants are relatively cheap to build, and decline in Korea, where they are more expensive.[31]

[31] Podkovalnikov (2004), pages 6 and 7. Belyaev and others (2002).

Figure 18 Schematic of Proposed Interconnections between the Russian Far East, North Korea (DPRK) and South Korea (ROK) in Year 2020



Source: Podkovalnikov (2002).

RELIABILITY IMPACTS OF POWER GRID ENHANCEMENTS IN SOUTHEAST ASIA

It is anticipated that the expansion of interconnections in the Greater Mekong Subregion, allowing for increased use of hydropower resources in China, Lao PDR and Myanmar, would enhance the reliability of electricity service in Thailand and Viet Nam. In large part, this is due to the fact that hydro facilities are generally available for service a greater percentage of the time than the coal- and gas-fired plants whose output they would be partially displacing. Hydro facilities also have better operating characteristics than coal-fired plants, in the sense that they can more easily be cycled up and down with very-short-term fluctuations in demand. Furthermore, the installed capacity of hydro plants (the capacity of their turbines) is generally well above their firm capacity (which is limited by the amount of water available to run through the turbines continuously). This means that hydro plants have substantial amounts of excess capacity during long periods of the year, which provides a reliability cushion in the event that other plants should fail.[32]

For Southeast Asia as a whole, the ASEAN Interconnection Master Plan Study has established that expanded power links would yield major cost savings, as shown in the following chapter of this report, without causing the reliability of power supply to be compromised. The AIMS optimisation approach treats reliability as a constraint, according to planning criteria set by ASEAN members.

[32] Doorman and others (2004).

Brunei Darussalam and the Sabah / Sarawak province of Malaysia plan their systems according to an "N-2" criterion that requires service to be maintained with the two largest generating units out of operation. Other areas in ASEAN define reliable service as maintaining a loss of load probability (LOLP) no greater than 24 hours (1 day) per year. In Peninsular Malaysia and Singapore, this LOLP criterion is deemed to require a 30 percent reserve margin of generating capacity over peak demand, while elsewhere it is deemed to require a planning reserve margin of only 15 percent. In assessing potential benefits of enhanced power grid interconnections, the AIMS study required that all of these reliability criteria be met. In addition, the study required that operating voltage not vary by more than 5 percent from nominal voltage, that system frequency not vary by more than 0.5 hertz, and that various other dynamic contingency criteria be met.[33]

CONCLUDING OBSERVATIONS

It seems apparent, from the information presented above, that strengthening and expanding power grids in the APEC region can enhance the reliability of electricity supply in several ways. Where grids are already highly developed, strengthening them can provide economies with greater flexibility to respond to the temporary loss of a major component of generating supply, as illustrated by the case of nuclear power plant outages in Japan. Strengthening grids can also reduce the likelihood and extent of general power outages, as shown by the example of North America. Where grids are still in the process of being formed, as in Northeast Asia and Southeast Asia, expanding them holds the promise of delivering economic and environmental benefits without compromising the reliability of service. Indeed, the development of cross-border power grids in Asia should make electricity supply more dependable by allowing economies to draw more readily on the spare generating capacity of their neighbours when their needs for power are greatest.

[33] ASEAN Interconnection Master Plan Study Group (2003), volume III, pages 17-19.

ECONOMIC BENEFITS OF POWER GRID ENHANCEMENT

INTRODUCTION

Enhancement of electric power grids can bring substantial economic benefits by extending the geographic scope of competition and making it possible for places where the costs of generating electricity are relatively high to obtain power from places where generating costs are lower. Where transmission grids are constrained or non-existent, the costs of generating power will generally differ from place to place. In fact, a difference in short-run marginal generating costs between two places clearly indicates that the ability to transmit power between them is limited, for otherwise suppliers in the higher cost area will buy from the lower cost area until costs in both areas are equal. Where limits on transmission are due to the absence of interconnections between two areas or to physical constraints on the carrying capacity of grids, as opposed to political or regulatory restrictions, extension or enhancement of grids can ease the limits and reduce overall costs.

In economies where transmission grids are well developed, as in Japan and North America, the value of grid enhancements may vary considerably from place to place and from time to time. When seasonal demand is relatively low, as in the spring or fall, or when hourly demand is relatively low, as it is late at night, the grids are usually unconstrained, power flows between them freely, and the economic value of grid enhancements is small. But when seasonal demand is at its height in summer or winter, or when hourly demand peaks, perhaps around dinnertime, the limits on grids may become pronounced in many places, the marginal costs of generating power may rise sharply, the differences in generating costs may be great, and the economic value of grid enhancements can be very large. By examining the differences in short-run marginal prices between two places over time, as well as the additional power flows between them if links between them were enhanced, it should be possible to determine the value of enhanced links between them. It should then be possible to determine where the value of enhanced links would be greatest.

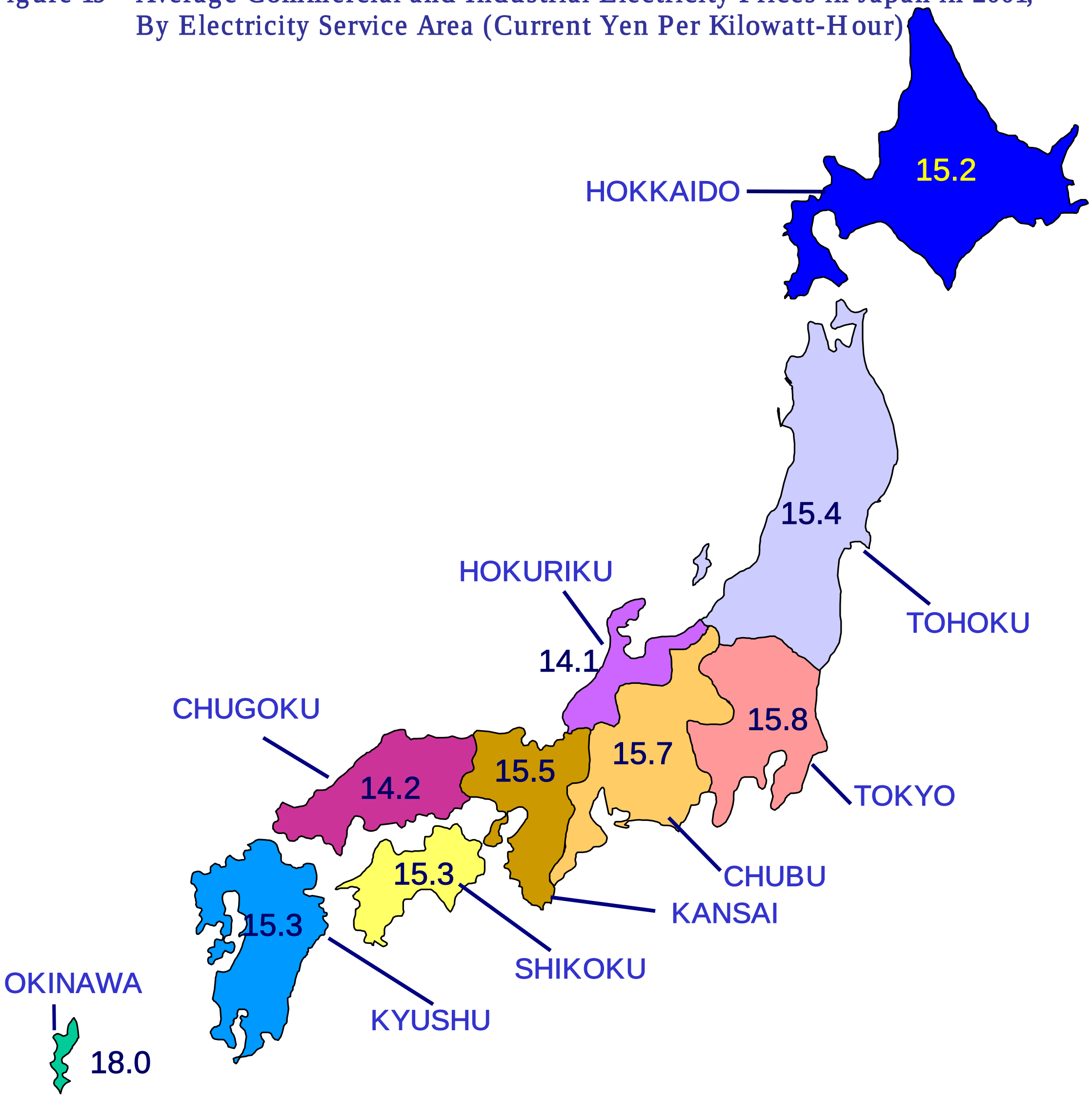
In economies between which transmission grids are not yet well developed, as in Northeast Asia and Southeast Asia, the value of grid interconnections can only be estimated if demand trends and planned additions to generating capacity in each economy are well understood. In economies with potential surplus resources of hydropower, nuclear power, or natural gas-fired power, the amount of surplus power available for export will depend upon how much new generating capacity is built and on how much of its output is absorbed by growing domestic power demand. In economies that export gas, the value of power exports will also depend on whether it is cheaper to export gas over newly constructed pipelines or to export gas by wire via gas-fired power plants. Hence, the economic benefits of power exports can only be estimated if there are reliable analyses of planned generating additions, future demand growth, and tradeoffs between gas and power grids.

Moreover, the value of new grid interconnections will depend in large part on the match between peaks and troughs of electricity demand in neighbouring economies. For a power export to take place at any given time, the exporter must have surplus electricity available at a cost which is lower than the marginal generating cost for the importer. The amount of surplus power available for export depends not only on the reserve margin of generating capacity over and above peak demand, but also on the extent to which demand at the moment is below the peak demand. On the buyer's side, generating costs will be highest, and the desire to import greatest, when demand is greatest. Thus, a reasoned assessment of the potential economic benefits of power trade requires a common understanding not only of growth in demand and generating capacity in each economy, but also of the daily and seasonal patterns of demand in each economy. It follows that if potential participants in a regional power grid are to reach a consensus on how the grid should take shape, reliable and current information on all of these items will need to be shared among them.

ECONOMIC BENEFITS OF POWER GRID ENHANCEMENTS IN JAPAN

Within Japan, the delivered price of electricity does not vary a great deal from area to area. As shown in the figure below, the average price of electricity to commercial and industrial customers ranges from a low of 14.1 yen per kWh in Hokuriku to a high of 18.0 yen per kWh in Okinawa. But excluding Okinawa, which is not interconnected with the rest of Japan, the highest average price, found in Tokyo, is 15.8 cents per kWh. The price differential between neighbouring areas ranges from zero (between Kyushou and Shikoku) to 1.6 yen per kWh (between Chubu and Hokuriku). In the latter instance, the savings to commercial and industrial customers from greater power trade would not exceed roughly 10 percent (a reduction of 1.6 yen from 15.7 yen per kWh).

Figure 19 Average Commercial and Industrial Electricity Prices in Japan in 2001, By Electricity Service Area (Current Yen Per Kilowatt-Hour)



Source: Federation of Electric Utilities, Japan

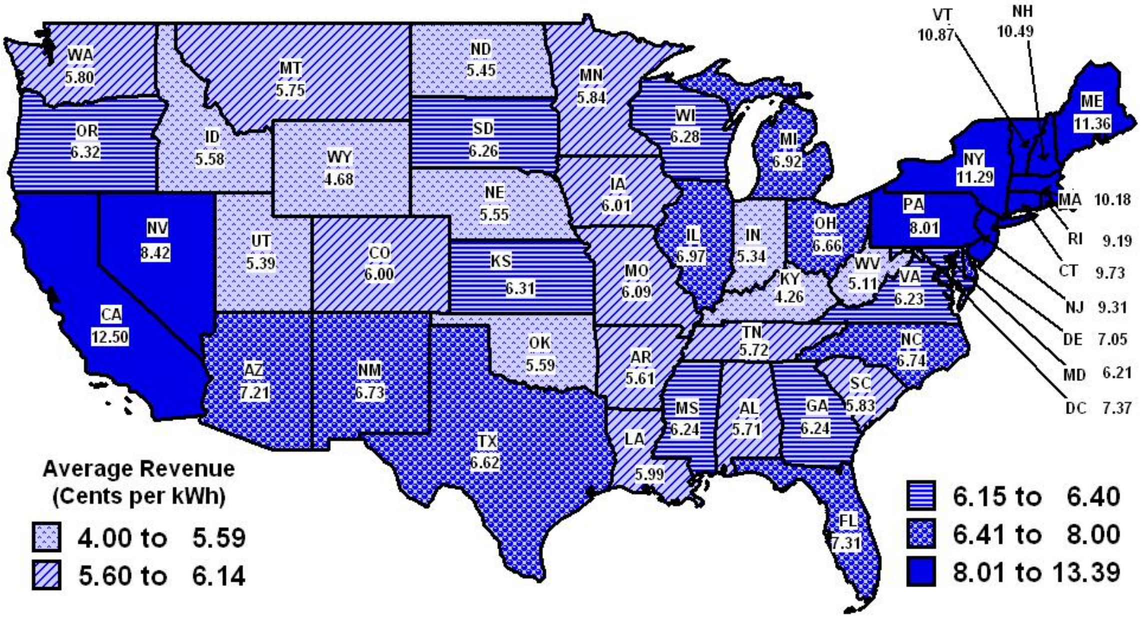
Yet even a 10 percent cost reduction on power bills might be very welcome to a commercial or industrial enterprise that is competing in international markets, particularly if its operations or products are electricity-intensive. It is also possible that differentials in short-run marginal generating costs are greater than 10 percent in certain places at times of peak demand. Thus, the potential economic value of increased power trade within Japan should not be entirely discounted.

Indeed, recent estimates by Japan's electric utility industry indicate that existing interconnections have made it possible to substantially reduce the reserve generating capacity that is required to ensure reliable service. Without the existing power grid, power producers would collectively have to hold a generation reserve of 11 to 13 percent above peak load. With the grid in place, the required generation reserve is only 8 to 10 percent. So Japan's electric power grid has made it possible to reduce the capital costs of generating capacity by roughly 3 percent. Since Japan had some 230 gigawatts of generating capacity in 2001, then assuming capital costs of roughly US$1 billion per gigawatt, the grid has brought capital savings on generating units of perhaps $7 billion.[34]

ECONOMIC BENEFITS OF POWER GRID ENHANCEMENTS IN NORTH AMERICA

There are fairly large differences in electricity prices between different parts of the United States. As shown in Figure 20, retail electricity prices can differ greatly even between neighbouring states. In California, for example, prices are roughly double those in Oregon and Washington to the north. In New York, prices are about twice as high as those in West Virginia, just two states to the south. Such price differentials are the primary basis for wholesale electricity trade, which allows cheaper power in one area to displace more expensive power in a neighbouring area. Insofar as the grid allows such cost-saving trade, it will yield economic benefits for the economy as a whole.[35]

Figure 20 State Retail Electricity Price Differentials in the United States in 2002



Source: US Energy Information Administration

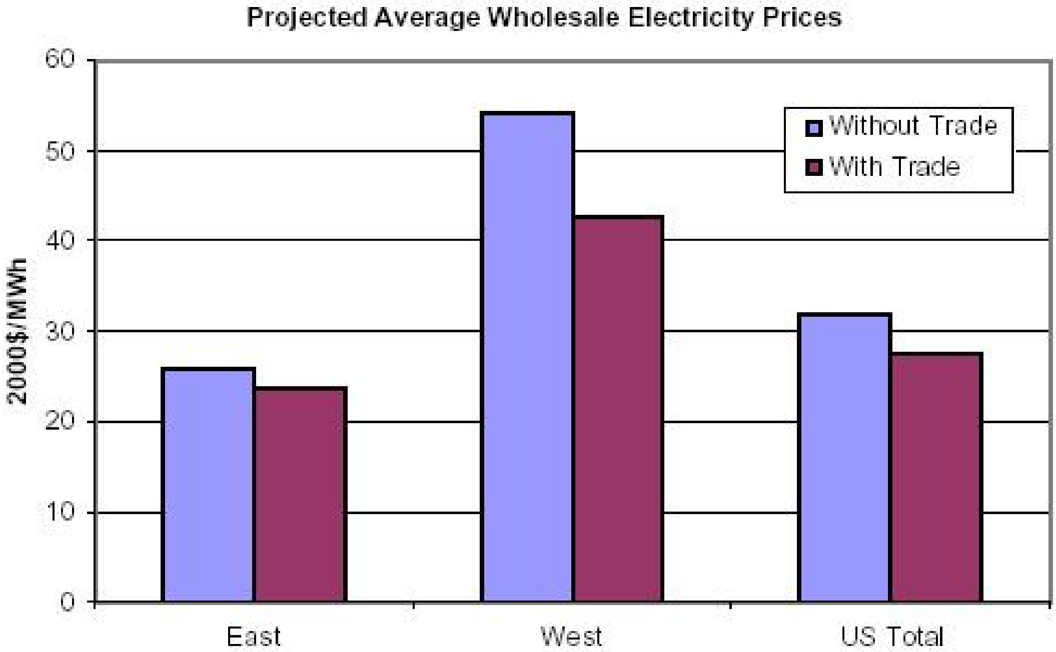
The economic value of the power grid in North America is indeed very substantial. Apart from the need to have strong interconnections to maintain reliable service, and the associated economic value of avoiding power outages, there are sizeable economic benefits from the wholesale power trade that the grid makes possible between regions. According to the US Department of Energy, as shown in Figure 21, interregional power trade reduces average wholesale electricity prices by 12 percent, or roughly from 3.2 cents to 2.7 cents per kilowatt-hour. With the wholesale market

[34] Kurihara (2003). See materials from sixth meeting of the Study on Neutral Organisation www.ne.jp/asahi/chu/ben/. Institute of Energy Economics, Japan (2003). Generating capacity figure excludes auto-production by industry.

[35] US Energy Information Administration (2003). Table of Average Revenue per Kilowatthour for Bundled and Unbundled Consumers by Sector, Census Division and State, 2002 (All Sectors).

trading about half of all the electricity sold to final consumers, delivered electricity costs are reduced by around 6 percent, lowering the economy's $224 billion annual electricity bill by $13 billion.[36]

Figure 21 Cost Reductions from Electricity Trade in the United States



Source: United States Department of Energy (2002). National Power Grid Study

However, the constraints that exist on the grid prevent the economic benefits of wholesale power trade from being quite a bit larger. With major transmission lines heavily loaded much of the time, as described in the previous chapter, many potential economic trades cannot occur. The National Transmission Grid Study estimated the costs of congestion in four major wholesale power markets: California, PJM (mainly covering Pennsylvania, New Jersey and Maryland), New York, and New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont). It found that if all economic transactions could occur across congested paths in these regions, assuming that all generators are willing to sell power at their marginal operating cost, consumer electricity bills would decline by $157 million per year. Assuming that constraints in fact allow generators to sell at prices well in excess of their costs, the consumer benefits would be greater. For example, if prices were to spike by 10 cents per kWh above marginal operating costs, the net benefits to consumers of relieving congestion in these regions would nearly triple to $447 million.[37]

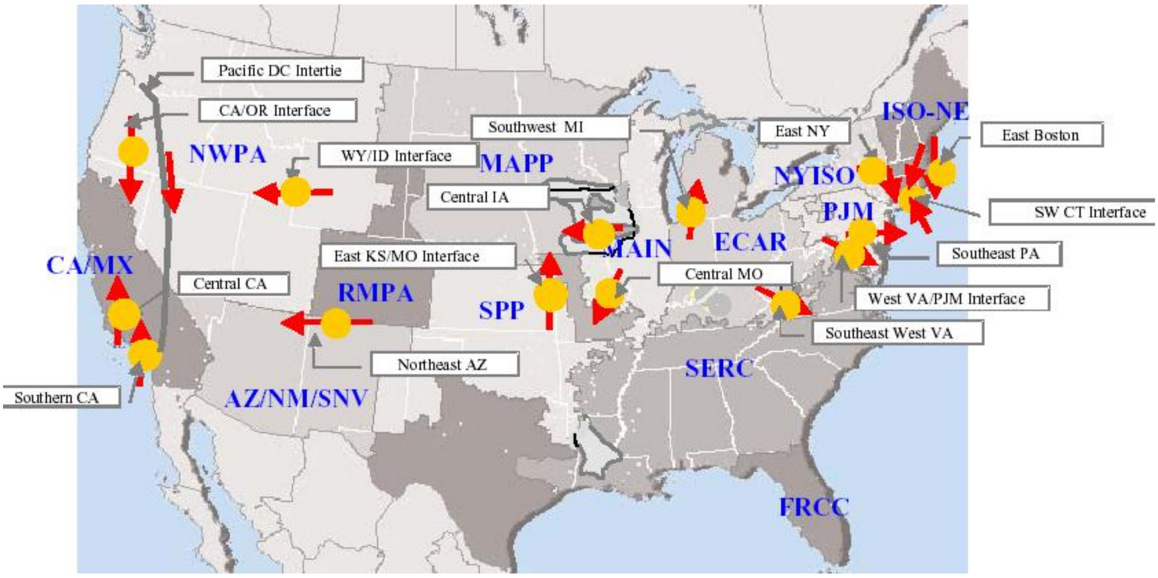
The overall costs of transmission constraints in the United States are in fact substantially higher. The Federal Energy Regulatory Commission (FERC) estimated costs for 16 separate transmission constraints as shown in Figure 22. These constraints were chosen because they had experienced a large number of transmission load relief (TLR) events that made it impossible for cheaper power from one area to displace more expensive generation in a neighbouring area, or because the areas they separated had shown large wholesale price differentials. The costs imposed by the constraints were estimated for the years 2000 and 2001 over the summer months of June, July and August when loads are highest and constraints are severest. For most constraints, the costs were fairly modest, ranging roughly from $5 million to $50 million. But for the constraint in eastern New York in the summer of 2000, FERC found that the cost of congestion exceeded $700 million.[38]

[36] US Department of Energy (2002), page 19.

[37] Ibid., pages 16-17.

[38] Ibid., pages 17-18. Federal Energy Regulatory Commission (2001).

Figure 22 Power Transmission Constraints in the Contiguous United States as Assessed by the Federal Energy Regulatory Commission (FERC) in 2001



Source: Federal Energy Regulatory Commission

Transmission constraints impose costs not only between regions, but also within regions. In New England, the ISO estimated the costs of congestion at between \$125 million and \$600 million per year. The cost of congestion along the Path 15 transmission corridor in California, meanwhile, was estimated by that state's ISO to cost \$222 million in the 16 months prior to December 2000.[39] More generally, the California ISO has estimated that relief of Path 15 congestion would reduce energy costs in California by \$100 million during a normal year and more than \$300 million during a dry year. By comparison, the estimated cost of an 84 mile (134 km) 500 kV line to relieve the Path 15 congestion, on which construction began in late 2003, is just \$300 million to \$400 million.[40]

The historical example of the Pacific Northwest - Pacific Southwest Intertie, which links hydro-power supplies in Oregon with fossil-fuelled generation in California, suggests that the estimated benefits of grid enhancements in North America may often be conservative. The Intertie consists of three 500 kV AC lines with a transfer capacity of 4,800 MW and a 1,000 kV DC line with a transfer capacity of 3,100 MW, for a total transfer capacity of 7,900 MW. It extends from Celilo on the Oregon-Washington border to Sylmar near Los Angeles in California, as shown in Figure 23. [41]

The economic benefits of the Pacific Intertie stem largely from seasonal diversity exchange. In summer, the Pacific Northwest has a lot of hydropower due to runoff from melting snow in the mountains, and this hydropower can be used to meet peak air conditioning loads in southern California. In winter, southern California has extra fossil-fuelled generating capacity since demand is off its peak, and this can be used to meet peak winter heating loads the Northwest.[42]

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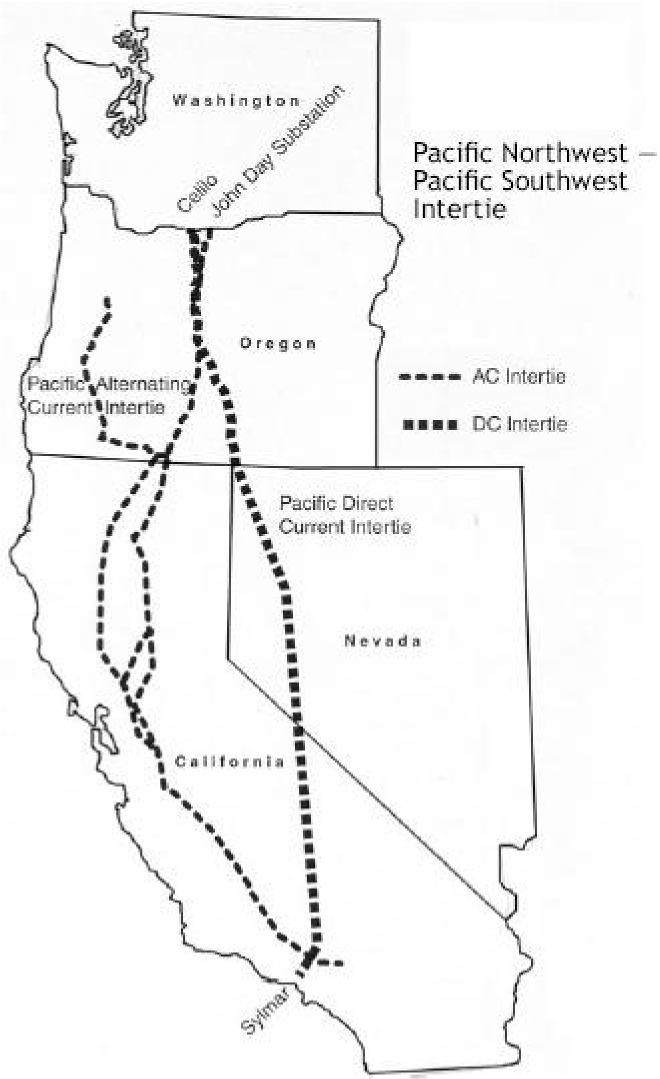
[39] US Department of Energy (2002), page 17. ISO New England (2001). California Independent System Operator (2001).

[40] US Department of Energy (2004). Danner and McConihe (2001), page 21. When the line was originally proposed by the Western Systems Coordinating Council in April 2001, its estimated cost was \$300 million. Successive DOE press releases refer to costs of \$230 million (July 23, 2001), \$300 million (October 18, 2001) and \$306 million (June 26, 2002). A further DOE press release (September 24, 2003), referring to ISO estimates that the line's costs would be recovered in four years and the line's benefits would be \$100 million in a normal year, implies a cost of perhaps \$400 million.

[41] Electric Power Group (2003). Northwest Power Planning Council (2001). Two of the AC lines, which originally entered service in 1969 with a capacity of 1,400 MW, were gradually upgraded to 2,000 MW in the early 1970s, 2,500 MW in the early 1980s, and 3,200 MW in 1980. The third AC line became available in 1993 with 1,600 MW of capacity. The DC line, which entered service in 1970 at an 800 kV rating with 1,440 MW of capacity, was upgraded to 1,000 kV and 2,000 MW of capacity by 1987 and to its current 3,100 MW of capacity by 1989.

[42] Damsky (2002).

Figure 23 Pacific Northwest – Pacific Southwest Intertie



Source: Northwest Power Planning Council

The seasonal benefits of the Pacific Intertie in fact have several distinct components:

- Southwest capacity benefit: reduced need for fossil-fuelled generating capacity to meet summer peak demand, which is met in part by imports from the Northwest.
- Northwest capacity benefit: reduced need for generating capacity to meet winter peak demand, which is met in part by imports from the Southwest.
- Southwest operating benefit: reduced use of gas and other fossil fuels, which are displaced by imported hydropower from the Northwest.
- Northwest operating benefit: greater availability of hydropower, as water in dams need not be depleted while electric energy is imported from the Southwest.[43]

At least the Southwest capacity and operating benefits have been far greater than originally anticipated when the first components of the Intertie entered service. The amount of hydropower available to the Northwest for export to the Southwest largely depends on US and Canadian entitlements to hydropower under the Columbia River Treaty of 1961. Under that treaty, upstream dams (three in Canada and one in the US) increase downstream generating capacity in the US. In

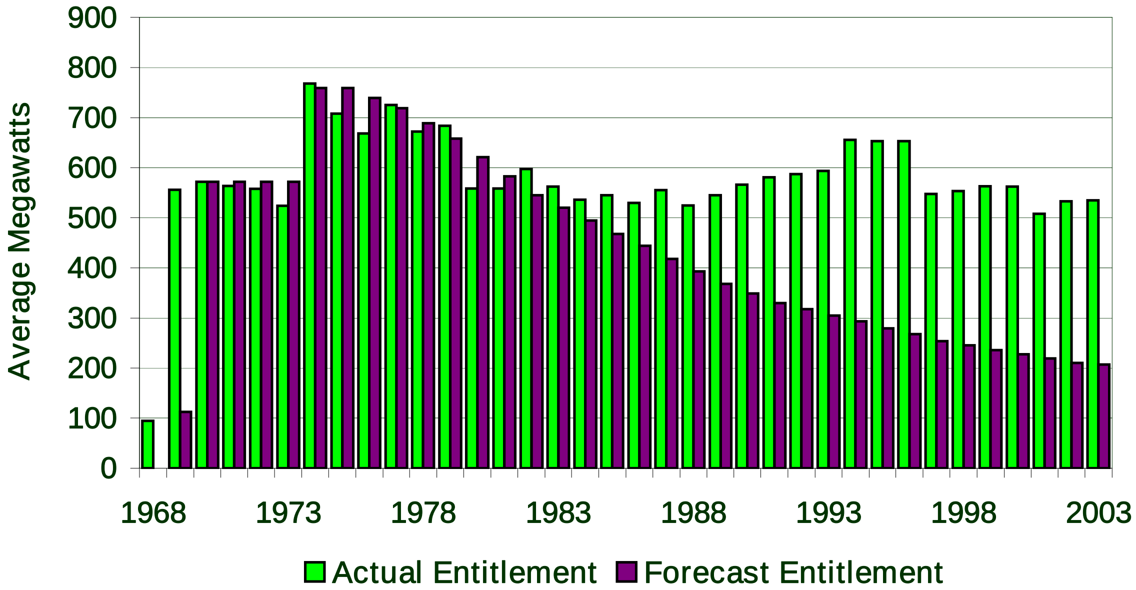
[43] Newton (2003).

return for developing dams upstream, Canada received the right to half the downstream generation. Canada then leased its portion of the downstream rights to the US Pacific Northwest, since it did not need the power for itself, and used part of the proceeds to pay for the upstream dams.[44] The resulting benefits to the United States have been greater than expected for three main reasons:

1) The amount of hydropower available from the Columbia River Treaty has been greater than expected, so that the US Pacific Northwest has had extra power at its disposal.
2) The rate of electric demand growth in the Pacific Northwest has been slower than expected, raising the portion of its power the Northwest can send to the Southwest.
3) The value of generating capacity to meet peak demand, displaced by seasonal trade between the Northwest and Southwest, has been greater than anticipated.[45]

Figure 24 compares the estimated and actual amounts of hydropower that were available to the US Pacific Northwest from its lease of Canada's Columbia River Treaty hydro rights. The darker bars show the average megawatts of capacity that were expected to be available when hydro production began in 1968. The lighter bars show the average megawatts of capacity that were actually available, according to calculations made under the treaty five years ahead of time. Since the early 1990s, as can be seen, the actual amounts have been about twice what was planned for.

Figure 24 Canadian Hydropower Entitlement from Columbia River Treaty



Source: Newton (2003).

Figure 25 shows how original projections of load growth in the Pacific Northwest were revised downward over time. The darker line shows the load projection that was made when hydropower from the Columbia River was first supplied in 1968. The lighter line shows the load projections that were made just five years ahead of time, which are far closer to the loads that materialised. As the figure shows, the originally forecast and actual demand in the Northwest have increasingly diverged over time, leaving much more electricity available for export to California.

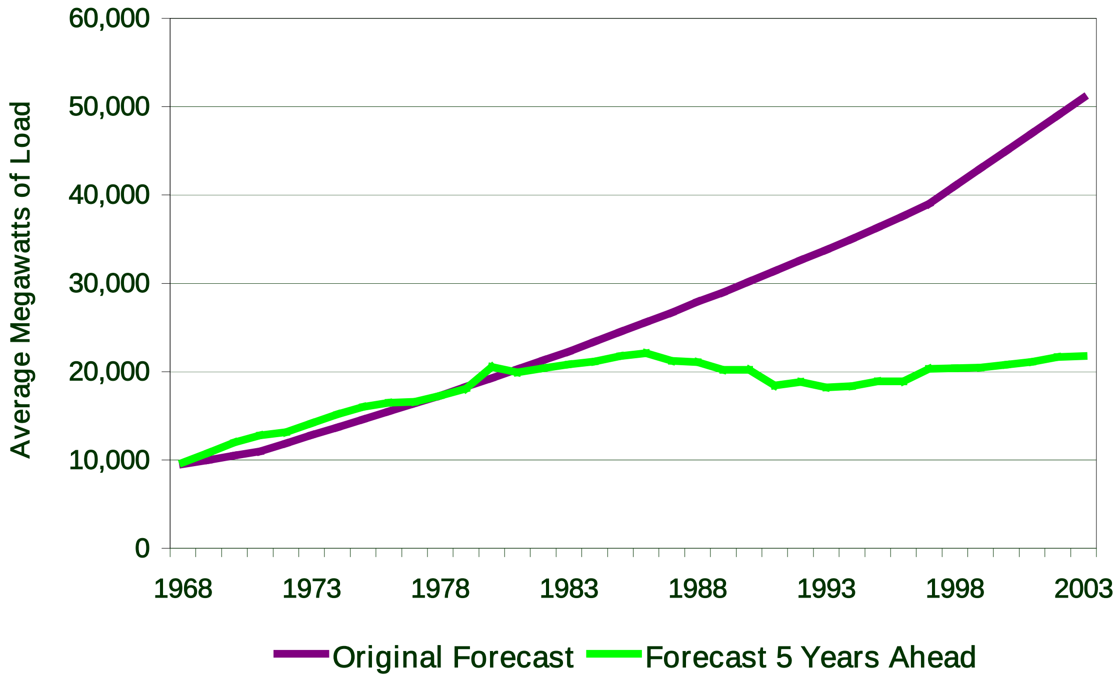
The operational benefit of the Intertie for California was estimated in a recent study performed for the California Energy Commission. Operational savings each year are calculated as the amount of energy imported times the difference between California's marginal cost of electricity production and the cost of energy imported. In nominal terms, total savings of nearly $7.2 billion from 1969 to

44 Government of Canada and Government of the United States (1961).

45 Newton (2003).

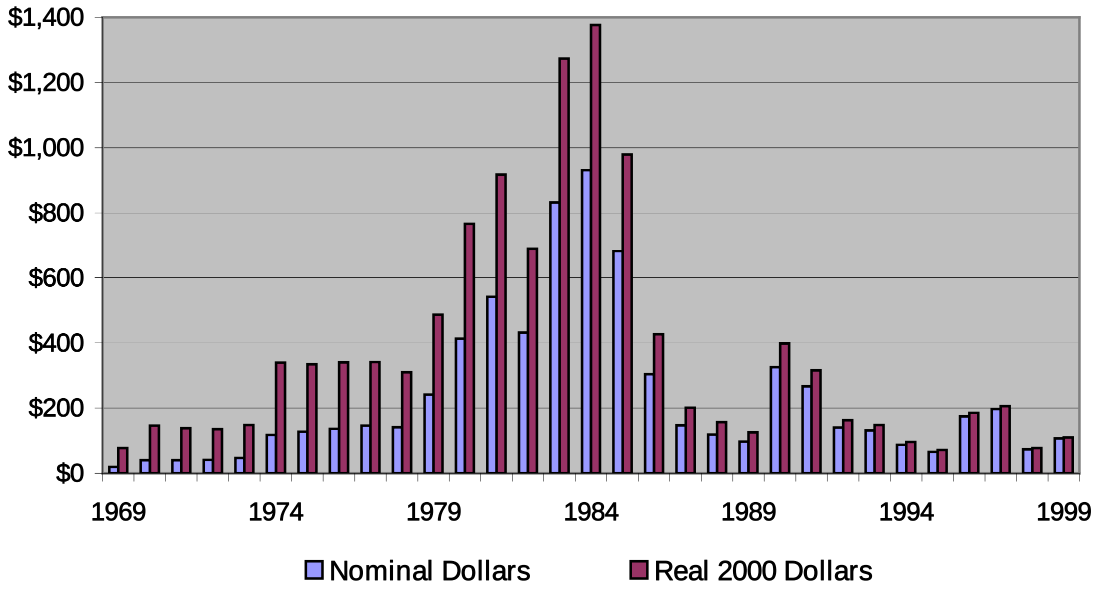
1999 were more than four times Intertie investment costs of $1.6 billion. In 2000 dollars, applying the GDP deflator, total savings of $11.5 billion are roughly three times total costs of $3.7 billion. Discounting to 1969 at a 5 percent real discount rate, savings of $6.1 billion are more than double costs of $3.0 billion.[46] The pattern of savings in nominal and 2000 dollars is shown in Figure 26.

Figure 25 Original and Revised Forecasts of Load in the U.S. Pacific Northwest



Source: Newton (2003).

Figure 26 Operating Savings from California Power Imports on the Pacific Intertie



Source: Electric Power Group (2003).

[46] Electric Power Group (2003), page 28. Investment costs of $296 million in 1969, $304 million in 1970, $200 million in 1989 and $350 million in 1993 are actual figures. Investment costs of $127 million in 1972, $142 million in 1982, and $152 million in 1987 were estimated using an average cost of $215,000 per MW. Discounting was done by APERC.

At the same time, considerable uncertainty surrounds the projected benefits of transmission line expansion, which depend on assumptions about future generating capacity and fuel costs. An example is offered by a recent analysis of the impacts of transmission grid expansion in the western United States through 2010, which employs two different sets of assumptions. In a study by the Western Governors Association (WGA), expansion of the grid is assumed to result in a great deal of displacement of gas-fired capacity by coal-fired and renewable generating capacity. In a study by Resources for the Future (RFF), which assumes that generating capacity is chosen according to a least-cost model, grid expansion is found to cause little change in the mix of generating capacity.

The WGA reasoned that in a baseline "gas" scenario, new gas-fired generating units could be located close to load centres, so that congestion on the transmission grid would not increase very much and little new investment in new transmission lines would be required. In an "other than gas" or transmission expansion scenario, however, a substantial share of incremental generation would be provided by new coal-fired, wind, hydro and geothermal power plants far from load centres, so that greater investment in new transmission facilities would be needed. The driver for the latter scenario was the potential to displace costly gas with cheap coal, since the WGA assumed average prices in 1997 dollars of $4.68 per million Btu for gas but just $0.73 per MBtu for coal.[47]

The RFF study assumed similar relative fuel prices (12 percent lower for gas and 15 percent lower for coal than WGA) but apparently found gas plants to have low enough capital and other costs to generate power more cheaply than coal plants overall. So in calculating a least cost capacity expansion path, RFF's model favoured gas plants both with and without transmission expansion. This result should probably be regarded with caution since North American gas prices have ratcheted upward in recent years and since the model's documentation indicates that the cost of gas- and coal-fired power in 2005 would differ by only 7 percent in the United States on average.[48]

Table 4 Two Views of Transmission Expansion in the Western United States (Projected Megawatts of Generating Capacity Additions through 2010)

	Western Governors Association View			Resources for the Future View		
Type of Generating Capacity	Baseline "Gas" Scenario	Transmission Expansion Scenario	Difference Between Scenarios	Baseline "Gas" Scenario	Transmission Expansion Scenario	Difference Between Scenarios
Gas	46,345 MW	24,744 MW	-21,601 MW	40,789 MW	41,156 MW	+367 MW
Coal	80 MW	18,010 MW	+17,930 MW	3,278 MW	3,317 MW	+39 MW
Hydro	762 MW	2,362 MW	+1,600 MW			
Wind	487 MW	4,167 MW	+3,680 MW	9,064 MW	8,434 MW	-630 MW
Geothermal	100 MW	1,500 MW	+1,400 MW			
Other	770 MW	770 MW	0 MW	1,076 MW	1,273 MW	+197 MW
Total	48,544 MW	51,553 MW	+3,009 MW	54,207 MW	54,180 MW	-27 MW

Sources: Transmission Working Group (2001). Bloyd (2004).

[47] Transmission Working Group (2001), pages 22-40. Bloyd and others (2002).

[48] Bloyd and others (2002), page 10. Paul and Burtraw (2002) show an average US cost per kWh of 4.82 cents for coal plants and 4.5 cents for gas combined cycle plants, for a cost gap of 0.32 cents. This assumes a 9% real cost of capital, new plant cost per kW of $1,530 for coal and $713 for gas, capacity factor of 81% for coal and 69% for gas, and plant lifetime of 15 years for coal and 22 years for gas. A sensitivity analysis may be performed assuming annualised capital cost per kW is the cost per kW times the amortisation factor $r\,(1+r)^n/[(1+r)^n - 1]$, which can be divided by 8,760 hours per year and the capacity factor to arrive at capital cost per kWh. Under base assumptions, capital cost per kWh is 2.68 cents for coal and 1.25 cents for gas, so the capital cost advantage for gas is 1.43 cents. If the real cost of capital were 6% instead of 9%, the capital cost per kWh would drop to 2.22 cents for coal and 0.98 cents for gas, narrowing the gap by 0.19 cents. If both types of plants were amortised over 30 years, the capital cost per kWh would drop to 2.10 cents for coal and 1.15 cents for gas, narrowing the gap by 0.48 cents. Combining sensitivities, with the real cost of capital lowered to 6% and plant lifetime extended to 30 years, the capital cost per kWh would drop to 1.57 cents for coal and 0.86 cents for gas, narrowing the gap by 0.72 cents. In the latter two cases, the capital cost gap would close by more than the baseline total cost gap of 0.32 cents, so coal would become the cheaper new plant option overall.

The WGA and RFF scenarios are compared in Table 4. In the WGA study, a transmission expansion scenario is assumed to be associated with about 22 GW less gas-fired capacity, 18 GW more coal-fired capacity, 7 GW more renewable capacity (from hydro, wind and geothermal plants), and 3 GW more capacity in all.[49] It may seem odd that transmission expansion would increase overall capacity requirements; this is apparently due to lower capacity factors for renewable units. In the RFF study, though, transmission expansion has no appreciable impacts on the capacity mix.

The resulting fuel and capital costs, as calculated by RFF's Haiku electricity market model, are shown for both sets of scenarios in Table 5. In both cases, transmission expansion costs about $0.5 billion per year. In the WGA case, this allows annual savings of $0.3 billion on generating capacity and $2.7 billion on fuel, for overall annual benefits of $2.5 billion. In the RFF case, transmission expansion brings offsetting annual savings on fuel and generating capacity of just $0.3 billion, so that transmission expansion imposes net annual costs of $0.2 billion.[50]

Table 5 Two Views of Transmission Expansion in the Western United States (Projected Annualised Fuel and Capital Costs in 2010)

	Western Governors Association View			Resources for the Future View		
Annualised Cost in Million 1997$	Baseline "Gas" Scenario	Transmission Expansion Scenario	Difference Between Scenarios	Baseline "Gas" Scenario	Transmission Expansion Scenario	Difference Between Scenarios
Generating Capacity	$2,600	$2,340	-$260	$6,797	$6,712	-$85
Fuel	$13,030	$10,296	-$2,734	$8,409	$8,240	-$169
Transmission Capacity	$156	$621	+$465	$156	$621	+$465
Total	$15,786	$13,257	-$2,529	$15,362	$15,573	+$211

Sources: Transmission Working Group (2001). Bloyd (2004).

ECONOMIC BENEFITS OF A POWER GRID FOR SOUTH AMERICA

The Regional Commission for Energy Integration (CIER) has estimated the economic benefits of planned transmission lines affecting Chile and Peru. These include 400 MW of transmission capacity between Chile and Peru, as well as 400 MW of capacity between Peru and Ecuador and 400 MW of capacity between Ecuador and Colombia. As shown in Table 6, savings on operating costs are expected to exceed US$400 million annually by 2010, when all of the planned lines are to be in operation. For Chile and Peru, operating costs will actually increase, but so will operating revenues. Hence, each economy will still be a net beneficiary of the interconnections.[51]

It appears that the reduction in operating costs for these lines will far exceed their investment costs. Ecuador's National Electricity Council (CONELEC) has estimated that a 250 MW link with Peru to be completed in 2007 will cost US$139 million, while a 200 MW link with Colombia to be completed in 2005 will cost US$46 million.[52] If costs scale in linear fashion, investment would total $228 million for 400 MW of links with Peru and $92 million for 400 MW of links with Columbia, or $320 million in all for the Peru-Ecuador-Columbia grid – less than the yearly operating savings.

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[49] Transmission Working Group (2001), pages 26-27. Bloyd (2004).

[50] Transmission Working Group (2001). Bloyd and others (2002). Bloyd (2004). Paul and Burtraw (2002), page 56. Capital costs are annualised assuming a 9% real cost of capital and a lifetimes of 15 years for coal plants, 22 years for gas plants and 17 years for wind turbines. Fuel costs are calculated assuming that new combined cycle gas plants are 48 percent efficient (using 7,137 Btu per kWh) and new coal plants are 37 percent efficient (using 9,161 Btu per kWh).

[51] CIER (1999a) and (1999b).

[52] CONELEC (2002).

Table 6 Annual Operating Cost Savings in 2010 from Three Planned Transmission Links in South America that Involve APEC Economies Chile and Peru

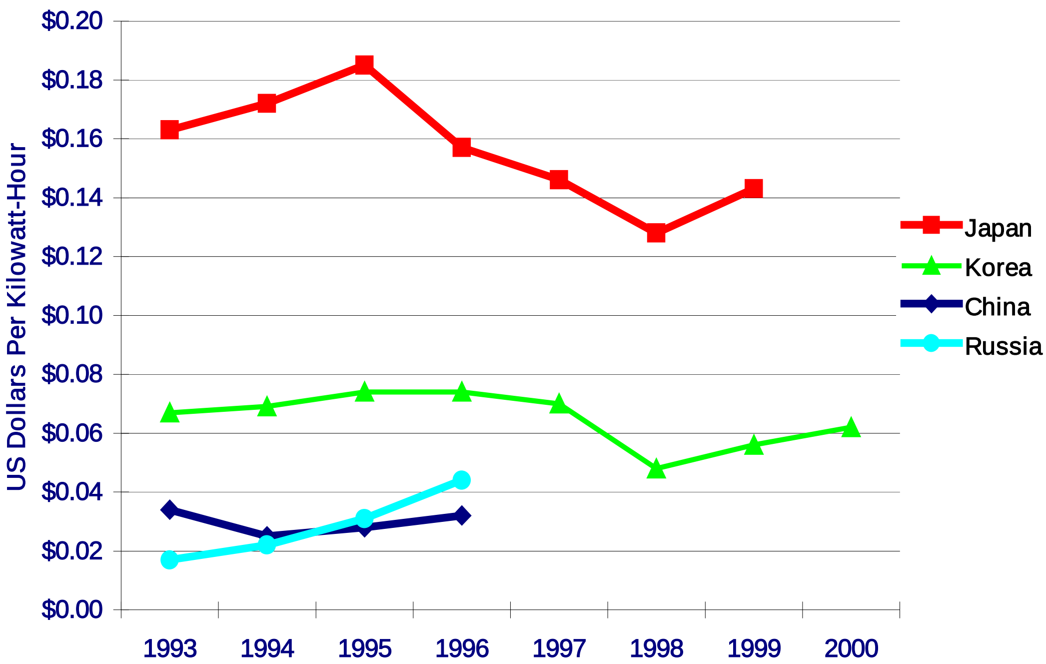
Interconnection Projects	Annual Operating Cost Without Interconnection	Annual Operating Cost With Interconnection	Net Annual Operating Cost Savings
Peru – Columbia – Ecuador Links	**$1,131 million**	**$778 million**	**$352 million**
Peru	$319 million	$410 million	(-$91 million)
Colombia	$269 million	$222 million	$47 million
Ecuador	$543 million	$146 million	$397 million
Chile – Peru Links:	**$696 million**	**$636 million**	**$61 million**
Chile	$375 million	$399 million	(-$24 million)
Peru	$321 million	$237 million	$85 million
Total for Three Transmission LInks	**$1,827 million**	**$1,514 million**	**$413 million**

Source: Regional Commission for Energy Integration. Assumes 340 MW Columbia-Ecuador, 400 MW Ecuador-Peru.

ECONOMIC BENEFITS OF A POWER GRID FOR NORTHEAST ASIA

There are major differences in the delivered costs of electricity among the economies of Northeast Asia, indicating that economic benefits from power grid interconnections between them could be large. As shown below, both industrial and household electricity prices are perhaps twice as high in Korea as in China or Russia, and more than twice as high in Japan as in Korea. It follows that substantial cost savings could be achieved through grid interconnections and power trade.[53]

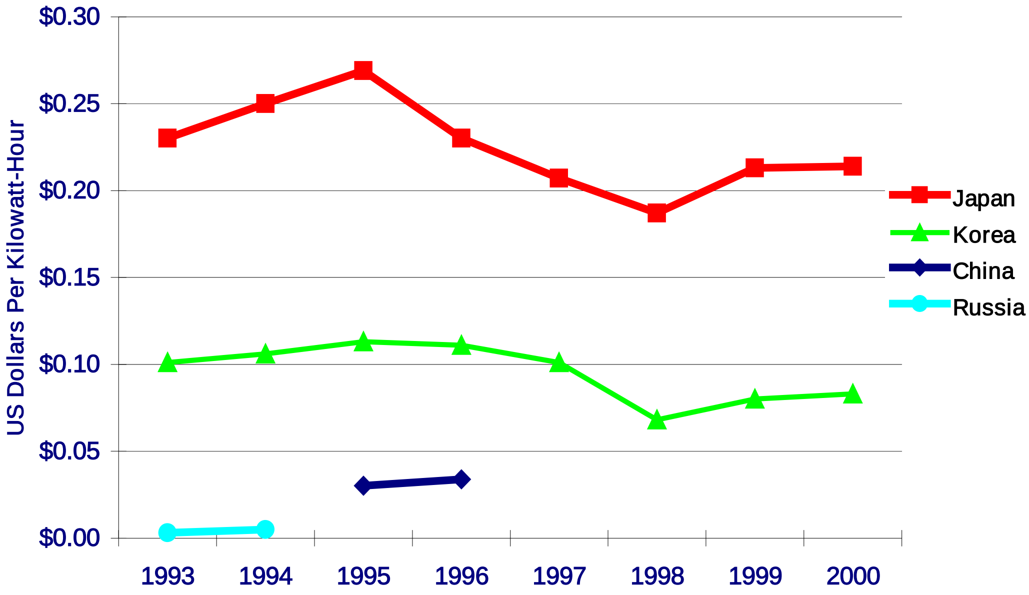
Figure 27 Industrial Electricity Prices in Northeast Asia



Source: International Energy Agency

[53] International Energy Agency (1999, 2000, 2001, 2002), tables 32 and 34.

Figure 28 Household Electricity Prices in Northeast Asia



Source: International Energy Agency

However, considerable care must be exercised in interpreting these charts. Prices in Russia and China have historically been determined in large part by state enterprises rather than by the market, and so they have not fully reflected the costs of generating and delivering power. As competition is introduced and prices rise toward market levels, the apparent cost advantage of generating power in these economies may diminish. A more technical consideration is that delivered prices include distribution costs for households and transmission costs for households and industries. This means that the differentials in generating costs, upon which the value of additional transmission links would depend, may be less than the differentials in delivered costs. And of course, new power links in Northeast Asia would have substantial costs, against which benefits would have to be weighed.

Nonetheless, the Energy Systems Institute at the Russian Academy of Sciences has found that several proposed interconnections in Northeast Asia would have clear net benefits. One power grid configuration analysed by the Energy Systems Institute involves the Russian Far East, Northeast China, and the Republic of Korea (ROK), either with or without power inputs from the Democratic People's Republic of Korea (DPRK). Another power grid configuration analysed by the Institute involves the Russian Far East and the two Koreas without participation by China.

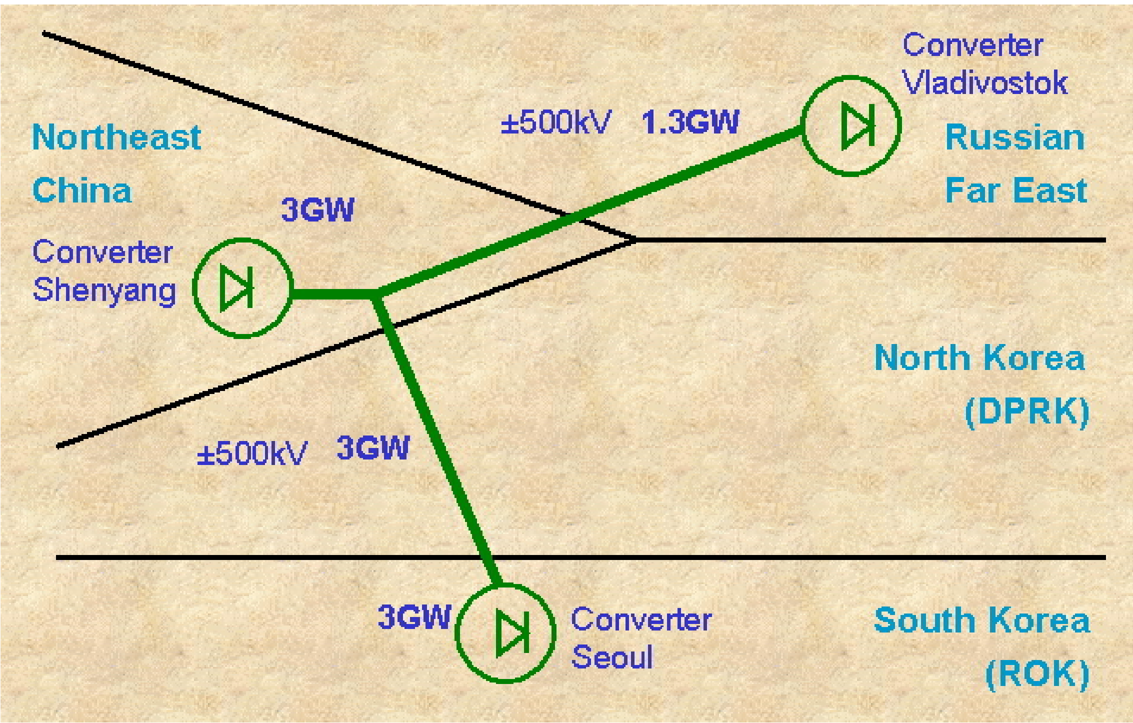
Figure 29 shows the proposed interconnection between the Russian Far East, Northeast China, and Republic of Korea. In this scheme, some 1,800 kilometres of 500 kV transmission lines would link the three areas. Power would flow towards Russia and China when their demand peaks during their winter, while power would flow towards Korea when its demand peaks during the summer. Two 640 MW nuclear power plants in Russia, approximated as 1.3 GW for the analysis, would displace 1.2 GW of thermal power in Korea (after transmission losses) during the summer months, as well as 0.5 GW of thermal power in Russia and 0.7 GW of thermal power in China (again after transmission losses) during the winter months. During the summer, power from thermal plants in China would reduce Korea's thermal capacity requirements by 1.3 GW. During the winter, power from thermal plants in Korea would reduce China's thermal capacity needs by 2.5 GW.[54]

To evaluate the capital cost savings that would result from the interconnection scheme, it is necessary to compare the costs of additional facilities with the savings from avoided facilities. The additional facilities include new transmission lines, converter stations and nuclear power plants. The avoided facilities are the thermal power plants that no longer need to be built as a result of the interconnections, including both direct capacity savings and reduced reserve capacity requirements.

[54] Podkovalnikov (2002), page 28.

As shown in the table below, the new facilities would cost about $4.5 billion while the savings from avoided facilities would amount to some $8.8 billion, for a net capital savings of about $4.3 billion.

Figure 29 Schematic of Proposed Interconnection between the Russian Far East, Northeast China, and Republic of Korea, with Line Crossing DPRK



Source: Podkovalnikov (2002).

There are also net fuel cost savings, which are equal to the additional fuel cost of uranium for nuclear power generation less the avoided cost of fossil fuel for thermal generation. The cost of uranium is estimated at 0.7 cents per kWh, while the cost of fossil fuel is estimated at 2.8 cents per kWh in Russia and China and 3.5 cents per kWh in Korea. When the capital costs are annualised and the fuel costs are added in, along with operation and maintenance costs for both power plants and transmission facilities, the net benefit per annum at assumed discount rates of 8, 10 and 12 percent is estimated at $830 million, $900 million and $990 million respectively. In approximate terms, the study concludes that net annual benefits would be on the order of $0.8 to $1.0 billion.[55]

In a variant of this case, a 900 MW converter is added at Pyongyang, the capital of PDRK, while the one at Shenyang in China is reduced to 900 MW. Seasonal power exchange occurs, with Russia exporting 1.5 GW of power in winter and 3.0 GW in other seasons. China imports 900 MW of power except during the summer, while DPRK imports 900 MW in spring and fall, 600 MW in winter and 300 MW in summer. ROK imports 1.2 GW in spring and fall and 2.7 GW in summer. The study estimates that there would be $3.7 billion in savings from reduced capacity requirements and $3.5 billion in savings from reduced costs made possible by substituting cheap imported electricity for expensive domestic electricity, with savings totalling $7.2 billion. On the other side of the ledger, there would be additional costs of $2.4 billion for transmission lines, $1.2 billion for converters and $1.45 billion for maintenance, with additional costs totalling $5.05 billion. Therefore, the net savings in this variant case would amount to some $2.15 billion over 15 years.[56]

55 Ibid., pages 28-30.

56 Ibid., pages 30-32.

Table 7 Estimated Capital Costs and Savings from the Proposed Interconnection Between the Russian Far East, Northeast China and Republic of Korea

Cost or Savings Element	Units Capacity	Cost per Unit	Total Cost
Additional Nuclear Generation	1.3 gigawatts	$2.0 billion / GW	$2.60 billion
Additional Transmission Lines	1,800 kilometres	$650,000/ km	$1.17 billion
Additional Converter Stations	7.3 megawatts	$0.1 billion / MW	$0.73 billion
Total Additional Capital Costs			**$4.50 billion**
Avoided Thermal Capacity Russia	0.5 gigawatts	$1.2 billion / GW	$0.60 billion
Avoided Thermal Capacity China	3.2 gigawatts	$1.2 billion / GW	$3.84 billion
Avoided Thermal Capacity Korea	2.5 gigawatts	$1.6 billion / GW	$4.00 billion
Avoided Thermal Capacity Costs			**$8.44 billion**
Avoided Reserve Capacity Russia	0.25 gigawatts	$0.3 billion / GW	$0.08 billion
Avoided Reserve Capacity China	0.5 gigawatts	$0.3 billion / GW	$0.15 billion
Avoided Reserve Capacity Korea	0.25 gigawatts	$0.4 billion / GW	$0.10 billion
Avoided Reserve Capacity Costs			**$0.23 billion**
Total Avoided Capital Costs			$8.77 billion

Source: Podkovalnikov (2002).

The proposed interconnection between the Russian Far East (RFE), North Korea (DPRK) and South Korea (ROK), for which the previous chapter describes the reliability benefits, would also have sizeable economic benefits. Since RFE is winter-peaking while the Koreas are summer-peaking, the interconnection would allow seasonal diversity exchange whereby RFE exports power during the summer. This would reduce requirements for new generating capacity through 2020 by 8 GW, or roughly a quarter. The interconnection would also allow a greater share of capacity to be built in the RFE, where construction costs are relatively low. As a consequence, while the interconnection itself would cost about $2 billion, it would reduce expenditures on new generating capacity by about $14.3 billion, for overall capital cost savings of $12.3 billion. If these capital cost savings are annualised at a discount rate of 8 percent and operating savings are added to them, total cost savings from the proposed interconnection could amount to some $2 billion per year.[57]

Table 8 Electricity Flows on an Interconnection between the Russian Far East, North Korea (DPRK) and South Korea (ROK), Terawatt-Hours Per Year

FROM:	To: Khabarovsk	To: Primorye	To: DPRK	To: ROK	Total Sent
Khabarovsk		3.5 (3.4 net)			3.5 (3.4 net)
Primorye	1.0 (0.9 net)		8.8 (8.4 net)		9.8 (9.3 net)
DPRK		0.4 (0.4 net)		16.0 (15.6 net)	16.4 (16.0 net)
ROK			6.7 (6.6 net)	8.9 (8.9 net)	15.6 (15.5 net)
Total Received	(0.9 net)	(3.8 net)	(15.0 net)	(24.5 net)	45.5 (44.2 net)

Source: Podkovalnikov (2002). Cross-border flows can be seen in diagonal pairs of boxes. For each trading pair (Khabarovsk/ Primorye, Primorye/DPRK, DPRK/ROK) imports net of losses are in green and gross exports are in red.

[57] Podkovalnikov (2004), pages 3 and 4. Podkovalnikov (2002), pages 15-21. Belyaev and others (2002).

The yearly electricity exchanges that might occur with an RFE-DPRK-ROK interconnection are shown in Table 8 above. Within RFE, Primorye would obtain 2.4 TWh of electricity from Khabarovsk (receiving 3.4 TWh and sending 1.0 TWh back). DPRK, in turn, would be a net recipient of 8.0 TWh from Primorye (receiving 8.4 TWh and sending 0.4 TWh back). ROK would then be a net recipient of 8.9 TWh from DPRK (receiving 15.6 TWh and sending 6.7 TWh back).[58]

The reduction in generating capacity requirements that an RFE-DPRK-ROK power link would make possible is detailed in Table 9 which follows. With an interconnection in place, new capacity builds would rise by 0.8 GW in the RFE, fall by 0.7 GW in DPRK and by 7.9 GW in ROK, and fall by a total of 7.8 GW for the three areas together. By fuel type, an interconnection would result in needs for 1.1 GW less coal-fired capacity, 0.9 GW less oil-fired capacity, 5.2 GW less nuclear capacity, and 0.6 GW less hydroelectric and hydro pumped storage capacity.[59]

Table 9 Comparative Requirements for New Generating Capacity through 2020 in RFE, DPRK and ROK with Separate and Interconnected Power Systems

Plant Type	Separate Power System Capacity				Interconnected Power System Capacity			
Type	RFE	DPRK	ROK	Total	RFE	DPRK	ROK	Total
Coal		2.2 GW	7.0 GW	9.2 GW		1.1 GW	7.0 GW	8.1 GW
Gas	0.2 GW		5.5 GW	5.7 GW	0.2 GW		5.5 GW	5.7 GW
Heavy Oil			0.9 GW	0.9 GW			0.0 GW	0.0 GW
Nuclear	1.2 GW	2.0 GW	12.3 GW	15.5 GW	2.0 GW	2.0 GW	6.3 GW	10.3 GW
Hydro		1.4 GW	0.1 GW	1.5 GW		1.8 GW	0.1 GW	1.9 GW
Pumped St.			1.0 GW	1.0 GW			0.0 GW	0.0 GW
Total	1.4 GW	5.6 GW	26.8 GW	33.8 GW	2.2 GW	4.9 GW	18.9 GW	26.0 GW

Source: Podkovalnikov (2002).

ECONOMIC BENEFITS OF A POWER GRID FOR SOUTHEAST ASIA

As mentioned earlier, the ASEAN Interconnections Master Plan Study (AIMS) identified eleven proposed transmission links as cost-effective options. These links were evaluated on the basis of an optimisation study that used generation planning software to select the least-cost mix of generation and transmission that satisfies reliability, stability and fuel supply criteria. However, the software could only evaluate two adjoining areas at a time, so the possibility of wheeling power from one system to another system through a third party was not considered.[60] Hence, there could well be additional cost-effective links in Southeast Asia that the initial study overlooked.

For seven of the selected interconnection projects, a comparison of costs and benefits in discounted 2000 US dollars is offered within the Interconnection Master Plan Study itself. As a group, the projects are projected to cost $356 million while reducing the cost of new generating capacity by $1,018 million, for net savings of $662 million.[61] Specific comparisons are as follows:

- In Subsystem A (Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam), the 300 MW link between Cambodia and Thailand (number 3 in Table 2) was found to reduce generation expenses by $193 million while requiring transmission investment of just $7 million, yielding expected net savings of $186 million.

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[58] Podkovalnikov (2002), page 18.

[59] Podkovalnikov (2002), page 18.

[60] ASEAN Interconnection Master Plan Study Group (2003), volume III, page 7.

[61] Ibid., page 29.

- In Subsystem B (Peninsular Malaysia, Singapore, Batam and Sumatra in Indonesia), the proposed 600 MW link between Peninsular Malaysia and Sumatra (number 6 in Table 2) was found to reduce generation expenses by $184 million while requiring transmission investment of $143 million, for expected net benefits of $41 million.
- Also in Subsystem B, proposed links to Singapore of 700 MW from Peninsular Malaysia, 600 MW from Sumatra, and 600 MW from Batam (numbers 7, 8, and 9 in Table 2) were found to reduce generation costs by $331 million while requiring transmission investment of $177 million, for net expected benefits of $154 million.
- In Subsystem C (Brunei Darussalam, West Kalimantan in Indonesia, Sabah and Sarawak in Malaysia, and Philippines), proposed 300 MW links to Sabah/Sarawak from Brunei Darussalam and West Kalimantan (numbers 10 and 11 in Table 2) were found to reduce generation costs by $310 million while requiring transmission investments of only $29 million, yielding expected net benefits of $281 million.

Table 10 Costs and Benefits of Selected Grid Interconnections in Southeast Asia (Present Value in 2000 US Dollars Discounted at 12 Percent Per Annum)

Interconnection Projects	Generation Cost Reduction	Interconnection Investment Cost	Net Savings
Subsystem A Link: 300 MW Cambodia – Thailand	$193 million	$7 million	$186 million
Subsystem B Links: 600 MW Peninsular Malaysia – Sumatra	$184 million	$143 million	$41 million
Subsystem B Links: 700 MW Singapore – Peninsular Malaysia, 600 MW Singapore – Sumatra (Indonesia), 600 MW Singapore – Batam (Indonesia)	$331 million	$177 million	$154 million
Subsystem C Links: 300 MW Sabah/Sarawak (Malaysia) – Brunei Darussalam 300 MW Sabah/Sarawak (Malaysia) – West Kalimantan (Indonesia)	$310 million	$29 million	$281 million
Total for Seven Transmission Projects	**$1,018 million**	**$356 million**	**$662 million**

Source: ASEAN Interconnection Master Plan Study (2003).

Three of the selected interconnection projects, to which funding has already been committed, were found to have significant net benefits in earlier studies. The required investments and benefits were estimated in the project development plans and incorporated in memoranda of understanding for their construction. Viet Nam has already committed to projects to import 1,887 MW of power from Laos (number 4 in Table 2) and export 200 MW of power to Cambodia (number 5). Thailand and Laos have signed an MOU for links of 2,015 MW to be completed in 2008 and another 1,578 MW to be completed in 2010, though Thailand would import power from Laos over these lines only if the prices were below its system avoided costs (number 1).[62]

The eleventh selected interconnection project, from Thailand to Myanmar (number 2 in Table 2), was selected without detailed analysis, on the basis that its undeveloped hydropower resources are known to be abundant and relatively low in cost. The Master Plan Study notes that while detailed analysis is currently precluded by limited information, "the abundant hydro potentials located in the Thalwin basin make it worthwhile to consider interconnection to Thailand without

[62] Ibid., pages 26-27.

the need for optimisation study. The hydro potentials in Myanmar could be developed to provide cheap and clean energy to ASEAN power grid in the future."[63]

In fact, the four last projects just described encompass most of the interconnections planned within the Greater Mekong Subregion. An analysis of three of these interconnections was recently performed by SINTEF Energy Research and Norconsult, on the basis of data developed by the Asian Development Bank. The analysis examines the economic impacts of the links between Laos and Thailand (number 1 in Table 2), between Myanmar and Thailand (number 2) and between Laos and Viet Nam (number 4). It also examines the economic impacts of several links not included in the AIMS report, including links between Cambodia and Viet Nam (to be completed by 2019), China and Thailand (2013), and China and Viet Nam (2019).

The SINTEF/Norconsult study examines the total costs of generation and transmission on the power system, including construction, operation and maintenance, in three "extended power cooperation" scenarios. Costs are calculated in US dollars for the period from 2005 to 2020 and discounted to 2001. In scenario A, all the transmission lines described are built, as detailed in the previous chapter. In scenario B, only those lines that will result in overall cost savings are built; the lines between Lao PDR and Thailand from Hongsa lignite plant to Mae Moh and from Na Bon to Udon Thani are thus excluded (these represent a portion of number 1 in Table 2). In Scenario C, the Tasang – Mae Moh link from Myanmar to Thailand is also excluded (number 2 in Table 2). Costs under the three scenarios are compared with a baseline of "limited power cooperation."

Table 11 Cost Comparison of Greater Mekong Subregion Power Grid Options

Cost Element	Baseline	Scenario A	Scenario B	Scenario C
Generation Cost	$44.354 billion	$42.457 billion	$42.283 billion	$42.755 billion
Transmission Cost	$0.056 billion	$1.499 billion	$1.213 billion	$1.010 billion
Total Cost	$44.410 billion	$43.956 billion	$43.496 billion	$43.765 billion
Cost Savings	$0.000 billion	$0.454 billion	$0.914 billion	$0.645 billion

Source: Doorman and others (2004).

All of the extended cooperation scenarios are found to result in cost savings relative to the baseline at an assumed 12 percent discount rate (weighted cost of capital), as shown in Table 11. The greatest savings are found to occur in scenario B, which includes all cost-effective options; they would amount to some $914 million. In scenario A, which includes some uneconomical units as well, the savings relative to the baseline would be only about half as much, or $454 million. In scenario C, which excludes a large hydro project along with the line over which its power would be sent, the savings are reduced by nearly a third, to $645 million. In all cases, the extra costs for transmission are more than outweighed by cost savings on generation. Beyond these direct cost savings, there would be $120 million to $210 million in savings, depending on the scenario, due to the higher reliability and improved operating characteristics of hydropower.[64]

Two interconnections that had been included in the initial ASEAN power grid proposal (numbers 13 and 14 in Table 2) were found by the ASEAN Interconnection Master Plan Study to be uneconomical and were not selected for further development. The study states flatly that "the interconnection between Peninsular Malaysia and Sarawak is not economical."[65] It also states that the Philippines are "the only country in ASEAN that will not be connected to the ASEAN Grid if the optimisation result is used as a basis for determination." This clearly implies that the proposed transmission link to the Philippines from Sabah in Malaysia was not found to be cost-effective. However, the report concedes that "further study may need to be conducted" in view of the many

[63] Ibid., page 27.

[64] Doorman and others (2004). At a 10 percent discount rate, the net present value of savings increases by about $500 million in each scenario, so that overall benefits of the three scenarios range from $0.9 billion to $1.4 billion.

[65] ASEAN Interconnection Master Plans Study Group (2003), volume III, page 25. This refers to project 13 in table 2.

new power plants that the Philippines will need if transmission links are absent.[66] Another two interconnections were also not selected, but for reasons less clear. These include lines from Thailand to Peninsular Malaysia (number 12 in Table 2) and Laos to Cambodia (number 15).

Following issuance of the initial AIMS report, an extended study was performed of ASEAN grid enhancement options. The extended study takes account of new demand forecasts and utilises improved software for grid optimisation. It also makes new assumptions about power supply, most notably including very substantial imports of hydropower from the Salawin project in Myanmar, with reduced imports of hydropower from Lao PDR. The changed assumptions about power supply imply much greater transmission capacity on the corridors from Myanmar to Thailand and (further "downstream") from Thailand to Peninsular Malaysia, as well as reduced transmission capacity on the corridor from Lao PDR to Thailand. The extended study considers the first eight (of eleven) lines assessed in the initial AIMS report, as well as two additional lines. Of the eight initial lines, as shown in Table 12 below, three (numbers 4, 5 and 8 in Table 2 and here) are identical in the extended study, and five are modified. The AIMS analysis of lines in Subsystem C (numbers 10 and 11 in Table 2) was not revisited in the extended study and should not be much affected.[67]

Table 12 Comparison of Initial and Extended ASEAN Interconnection Studies

Interconnection Project	Capacity in AIMS Study	Capacity in Extended Study	Start Date in AIMS Study	Start Date in Extended Study
1. Thailand – Lao PDR	2,015/ 1,578 MW	920 MW	2008/ 2010	2010
2. Thailand – Myanmar	1500 MW	5,600/ 5,600 MW	2013	2014/ 2017
3. Thailand – Cambodia	80/300 MW	80 MW	2004/ 2016	2004
4. Lao PDR – Viet Nam	1,887 MW	1,887 MW	2007/ 2016	2007/ 2016
5. Viet Nam – Cambodia	80/ 120 MW	80/ 120 MW	2003/ 2006	2003/ 2006
6. P. Malaysia – Sumatra	600 MW	1,200 MW	2008	2008
7. P. Malaysia – Singapore	700 MW	600 MW	2012	2009
8. Sumatra – Singapore	600 MW	600 MW	2014	2014
9. Viet Nam – Thailand	N/A	700 MW	N/A	2012
10. Thailand – P. Malaysia	N/A	3,500 MW	N/A	2008

Source: Chonglertvanichkul (2004).

Table 13 Gross Cost Savings from New Interconnections in Five ASEAN Economies

ASEAN Economy	Cost Without Interconnection	Cost with Interconnection	Gross Saving from Interconnection
Peninsular Malaysia	$36,162 million	$35,268 million	$894 million
Sumatra (Indonesia)	$12,931 million	$11,702 million	$1,229 million
Singapore	$15,259 million	$14,826 million	$434 million
Thailand	$53,820 million	$53,030 million	$790 million
Viet Nam	$27,468 million	$27,346 million	$122 million
Total for Five Economies	$145,640 million	$142,172 million	$3,468 million

Source: Chonglertvanichkul (2004).

The extended study finds substantial benefits from enhanced power system interconnections in ASEAN apart from those that might result from enhanced utilisation of hydropower resources. Considering only those projects that do not involve hydro-rich Myanmar, Lao PDR or Cambodia (projects 6 through 10 in Table 12), the extended study finds gross savings of $3,468 million,

[66] Ibid., page 28. This refers to project 14 in table 2.

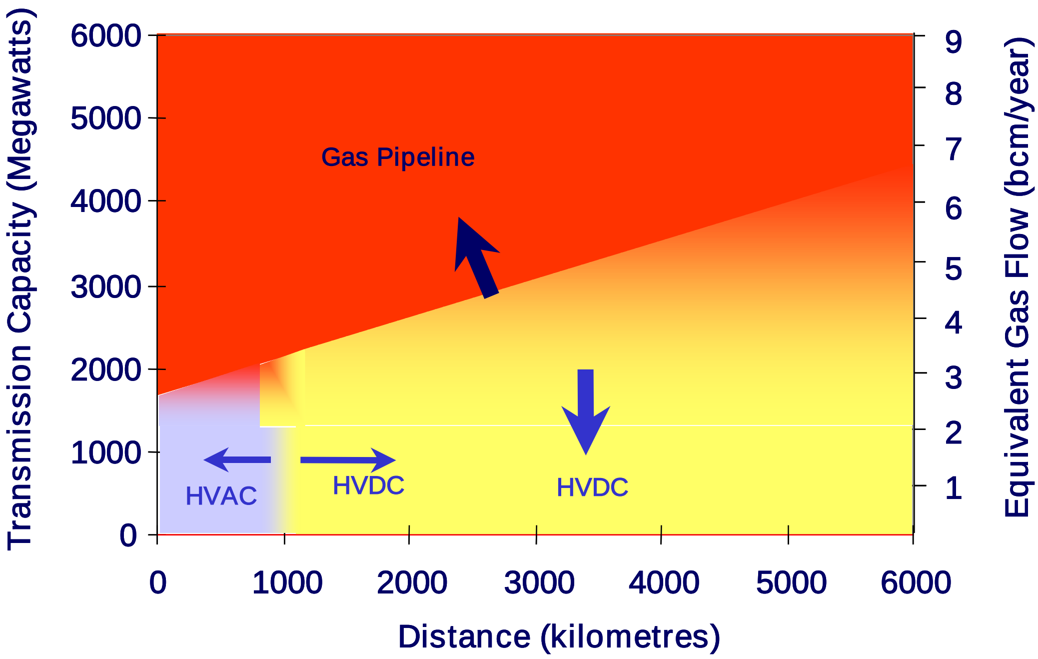
[67] Chonglertvanichkul (2004).

transmission costs of $1,059 million, and net savings of $2,409 million. Of the net cost savings, $1,661 million (69 percent) result from reduced investment requirements, $733 million (30 percent) from economy exchange allowing a reduction in fuel costs, and $15 million from improved reliability. Since overall investment declines by $1,661 million even though transmission investment rises by $1,059 million, one may also infer that investment in generating facilities declines by $2,720 million. Gross savings, before netting out transmission costs, are shown in Table 13 above.[68]

TRADEOFFS BETWEEN GAS AND POWER GRIDS

In deciding which elements of proposed electric power grids should be built, at least where the new power lines would largely be used to transport the output of gas-fired power plants, it is important to assess whether it would be most cost effective to transport gas by wire in the form of electricity or rather to transport gas itself through pipelines or LNG terminals.

Figure 30 Comparative Economics of Electric Transmission Lines and Gas Pipelines for Different Assumed Transmission Line Capacities and Distances



Source: Michael Williams, Shell Companies in North East Asia (2001). Analysis is based on average lifetime costs of electric transmission lines and natural gas pipelines on overland routes, without intermediate off-takes. Equivalent gas flows are calculated on the basis of a combined-cycle gas turbine operating at 55 percent efficiency, with one megawatt-hour equivalent to 1.54 Bcm per year and each cubic metre of gas holding 37.2 megajoules of net energy.

Industry experts generally agree that expansion of power transmission grids is more cost-effective than expansion of gas pipeline grids unless very large amounts of gas are being moved. That is because gas pipelines have relatively high fixed costs and relatively low variable costs per kilometre or cubic metre. The practical implications can be seen in Figure 30. If less than 2 gigawatts of power interconnections are contemplated, electric grid expansion will almost always be more cost-effective than gas pipeline grid expansion. As the planned distance for moving gas increases, the ceiling below which gas by wire makes sense increases. For moving gas 3,000 kilometres, gas by wire makes economic sense for capacities of 3 gigawatts or less. To move gas 5,000 kilometres, gas by wire makes economic sense for capacities of 4 gigawatts or less.

[68] Ibid. The study finds cost of $190 million for the transmission line from Thailand to Peninsular Malaysia, $102 million for the line from Peninsular Malaysia to Singapore, $544 million for the line from Peninsular Malaysia to Sumatra, $165 million for the line from Sumatra to Singapore, and $58 million for the line from Thailand to Viet Nam.

In Northeast Asia, the issue of whether electric transmission lines or gas pipelines would be preferable might seem to arise with respect to a couple of the interconnections proposed. The link from Bratsk in East Siberia to Beijing in North China would carry 3 GW of power over 2,600 km. The link from Uchur in the Russian Far East to Shenyang in Northeast China and Seoul in South Korea would carry 3.5 GW of power over 3,500 km. According to the figure, both of these long-distance, high-capacity power lines might be economically replaced by gas pipelines if their main purpose were to ship gas-fired power from Russia to China and Korea. However, if the proposed Vladivostok-Shenyang-Seoul link may be taken as an indication, as described above, such massive interconnections might in fact be expected to foster seasonal diversity exchange between nuclear power in Russia and thermal power in China (presumably coal-fired for the most part) and Korea.

In Southeast Asia, the issue of how best to balance gas and electric transmission capacity would seem to be more pressing. Brunei Darussalam, Indonesia and Malaysia, which are major exporters of gas, would be linked by both the ASEAN Power Grid and the Trans-ASEAN Gas Pipeline. But the various ASEAN Power Grid links involving these economies, which are listed as projects 6 through 11 in Table 2, have aggregate transmission capacities between 300 MW and 700 MW. These links are thus well below the threshold where gas pipelines would be a less costly alternative. In the extended ASEAN interconnection study, described above, the link between Peninsular Malaysia and Sumatra would be expanded to 1,200 MW, which is still well below the threshold, but a proposed link between Peninsular Malaysia and Thailand would have a capacity of 3,500 MW, which is not. However, the latter interconnection would be mainly intended not for the transmission of gas-fired power from Malaysia to Thailand (though some might well occur), but rather for the transmission of hydropower from Myanmar through Thailand to Malaysia.

In summary, then, it does not appear that any major proposed power grid interconnections among the economies of Northeast or Southeast Asia would be displacing more economically viable natural gas pipelines. In large part, this is because the enhanced power grid links would allow the exchange not just of gas-fired power, but also of coal-fired, nuclear and hydroelectric power. While some proposed power grid links would carry a significant component of gas-fired power, these links would not be large enough or long enough to make piped gas cheaper than gas by wire.

CONCLUDING OBSERVATIONS

It is clear that strengthening and expanding electric power grids can yield significant economic benefits in a wide variety of circumstances. Where grids are already well developed, as in Japan and North America, strengthening them can lower capital costs by reducing generating capacity reserve requirements. Strengthening grids can also lower operating costs by relieving congestion that prevents the least-cost available generating options from being utilised to the fullest possible extent. Where grids are at an early stage of development, as in Northeast and Southeast Asia, expanding them can substantially reduce the costs of delivering power by reducing overall needs for new generating capacity and by taking greater advantage of generating options with relatively low costs.

At the same time, the magnitude of economic benefits from enhanced electric power grids is often quite uncertain. If too much is invested in grid enhancements without adequate offsetting cost reductions from reduced capacity requirements and operating costs, the benefits may be less than anticipated or even negative. On the other hand, if conservative assumptions are made about the amount of low-cost generating capacity that will be available to serve neighbouring regions over time, the benefits of investing in power grid enhancements may be greater than originally imagined.

In view of both the large potential benefits of expanded power girds and the considerable uncertainty that surrounds their magnitude, it is important for neighbouring economies to reach a consensus about which grid enhancements are worthwhile and which should have greatest priority. In this sense, the highly collaborative planning process involved in the ASEAN Power Grid project, clearly backed by government leaders and supported by power system experts, is a valuable model. If proposed enhancements to the power grid in Northeast Asia are to achieve sufficient support and momentum to be realised, a similar process, with similar political backing, may well be needed.

ENVIRONMENTAL BENEFITS OF POWER GRID ENHANCEMENT

INTRODUCTION

Where new or reinforced power grid interconnections boost electricity trade among places with different energy resource endowments, there can be important benefits for the environment. Hydroelectric power, wind power sources and nuclear power have far lower emissions of atmospheric pollutants than fossil-fuelled power. Moreover, gas-fired power has substantially lower emissions than coal-fired power. With lower remissions of particulates (soot), there is reduced incidence of health effects, especially in urban areas. With lower emissions of nitrogen oxide and sulphur dioxide, there is less potential for regional production of acid rain. With lower emissions of carbon dioxide, there is less contribution to atmospheric greenhouse gases and global warming.

The environmental benefits of increased power trade are especially promising in the APEC region. China and Russia have very large undeveloped wind and hydropower resources that could displace substantial amounts of coal and gas in both economies. Japan and Korea have large nuclear power programmes that could also displace coal and gas if expanded, both internally and externally. Russia has vast reserves of natural gas that could displace coal at home or in China if the environmental advantages of gas were considered to outweigh the conventional economic advantages of coal for electricity generation. Gas reserves in Malaysia, Indonesia and Brunei Darussalam could also be used to displace coal in China or Southeast Asia. Canada still has significant undeveloped hydropower resources, as well as an active nuclear power programme, that could displace sizeable amounts of coal- and gas fired power in the United States.

Unfortunately, the potential environmental benefits of enhanced power trade in the APEC region have not been estimated in any comprehensive fashion. However, a number of studies have estimated the benefits of expanding the capacity of particular interconnections by specific amounts under speculative assumptions about the value per unit of reducing emissions of various pollutants. In addition, there is reliable information on the magnitude of undeveloped hydropower, wind and natural gas resources in each economy. Thus, it is possible to get a rough a sense of how large the overall environmental benefits of enhanced power links among APEC economies might be.

COMPARATIVE ENVIRONMENTAL IMPACTS OF DIFFERENT POWER SOURCES

As a general rule, renewable and nuclear power produce far lower atmospheric emissions of sulphur dioxide, nitrogen oxide, and carbon dioxide than power produced from coal, oil or gas. In addition, among the fossil fuels, coal generally results in higher atmospheric emissions than oil or gas, and older coal-fired power plants may produce high amounts of particulates (soot). In modern coal plants, however, particulates and sulphur dioxide are nearly eliminated while nitrogen oxides are also substantially reduced. So the net environmental benefits of displacing coal-fired power with gas-fired or renewable power depend on the technology assumed for new coal plants.

Nonetheless, it is possible to make a reasonable set of assumptions about the atmospheric emissions from each type of power plant in a typical situation, with the understanding that what is typical may vary from region to region and may differ from actual emissions in particular situations. One such set of assumptions was recently made by KOGAS in Korea, focusing on the contributions of different kinds of power plants to global warming (carbon dioxide emissions), ozone depletion (chlorofluorocarbon-11 emissions), acid rain (sulphur dioxide and nitrogen oxide emissions), and the eutrophication or algae clogging of waterways (phosphate emissions).[69]

[69] Yoon, Kim and Park (2003), page 5.

The emissions from one gigawatt-hour (one million kilowatt-hours) of generation at each type of plant are shown in Table 14. The impact of moving a GWh of generation from one type of plant to another is shown in Table 15, where it can be seen that the impacts of moving from coal to LNG and the impacts of moving from LNG to nuclear sum to the impacts of moving from coal to nuclear. Since the normal emissions of nuclear plants are minimal as are those of renewable energy plants, the environmental impacts of moving from coal or LNG to hydro or wind power would be similar to those of moving from coal or LNG to nuclear power.

Table 14 Environmental Emissions per Gigawatt-Hour by Type of Power Plant

Type of Impact	Coal	B-C Oil	LNG	Nuclear
Global Warming (kg CO_2)	9.24×10^5	7.49×10^5	6.23×10^5	9.21×10^0
Ozone depletion (kg CFC_{11})	2.75×10^{-3}	3.92×10^{-1}	1.22×10^{-3}	3.55×10^{-8}
Acidification (kg SOx)	2.87×10^3	2.52×10^3	4.21×10^2	4.73×10^0
Acidification (kg NOx)	1.33×10^3	1.52×10^3	7.01×10^0	2.38×10^0
Eutrophication (kg phosphate)	2.47×10^2	2.82×10^2	1.30×10^2	4.42×10^{-1}

Source: KOGAS.

Table 15 Change in Environmental Emissions per Gigawatt-Hour by Changing the Source of Electricity Generation from One Type of Power Plant to Another

Type of Impact:	Coal to LNG	LNG to Nuclear	Coal to Nuclear	Oil to LNG
Global Warming (kg CO_2)	-3.01×10^5	-6.23×10^5	-9.24×10^5	-1.26×10^5
Ozone depletion (kg CFC_{11})	-1.53×10^{-3}	-1.22×10^{-3}	-2.75×10^{-3}	-3.91×10^{-1}
Acidification (kg SOx)	-2.45×10^3	-4.21×10^2	-2.87×10^3	-2.10×10^3
Acidification (kg NOx)	-1.32×10^3	-4.63×10^0	-1.33×10^3	-1.52×10^3
Eutrophication (kg phosphate)	-1.17×10^2	-1.30×10^2	-2.47×10^2	-1.52×10^2

Source: KOGAS.

It is then possible to arrive at an indicative estimate of the potential environmental benefits of a new transmission link that allows one type of power to be substituted for another. Suppose, for example, that a line operates at an average of 80 percent of capacity (with the understanding that an actual line would have loadings that were lower or higher). Then for every year of 8,760 hours, a GW of new transmission capacity would result in 8,760 x 0.8 = 7,008 GWh of substitute electricity generation. So multiplying the figures in Table 15 by 7,008, we can roughly estimate the annual environmental impacts of installing a 1 GW transmission line for each assumption about which type of generation is substituted, as shown in Table 16. In practice, a mix of different power sources would be used to generate electricity, and the actual benefits would differ according to the mix.

Table 16 Yearly Change in Environmental Emissions per Gigawatt of Transmission Capacity Used to Switch from One Type of Electricity Generation to Another (Assuming Average Transmission Line Loading of Eighty Percent)

Type of Impact:	Coal to LNG	LNG to Nuclear	Coal to Nuclear	Oil to LNG
Global Warming (kg CO_2)	-2.11×10^9	-4.37×10^9	-6.48×10^9	-8.83×10^8
Ozone depletion (kg CFC_{11})	-1.07×10^1	-8.55×10^0	-1.93×10^1	-2.74×10^3
Acidification (kg SOx)	-1.72×10^7	-2.95×10^6	-2.01×10^7	-1.47×10^7
Acidification (kg NOx)	-9.27×10^6	-3.24×10^4	-9.30×10^6	-1.07×10^7
Eutrophication (kg phosphate)	-8.20×10^5	-9.11×10^5	-1.73×10^6	-1.07×10^6

In approximate terms, then, the use of a gigawatt of transmission capacity to switch from coal-fired to gas-fired power at an 80 percent capacity factor would reduce carbon dioxide emissions by

2.1 million tonnes, sulphur dioxide emissions by 17,000 tonnes and nitrogen oxide emissions by more than 9,000 tonnes each year. The use of a gigawatt of transmission capacity to switch from gas-fired to nuclear power would reduce CO_2 emissions by 4.4 million tonnes, SOx emissions by nearly 3,000 tonnes, and NOx emissions by around 30 tonnes. Switching from coal-fired to nuclear capacity would sum the impacts of coal-to-gas and gas-to-nuclear switching, with yearly reductions in the order of 6.5 million tonnes for CO_2, 20,000 tonnes for SOx and 9,000 tonnes for NOx.

Of course, a comprehensive assessment of environmental impacts would evaluate additional factors beyond those cited above. For hydropower plants, these would include the impacts on fish and other aquatic life, as well as visual impacts, which are highly site-specific. For nuclear plants, these would include the risks of possible accidents at the plants or leakage of fissile products during their transportation or storage, which are low in probability but high in potential consequence. It could be argued, however, that since many hydropower plants and most nuclear power plants operate in baseload mode, which is to say most of the time, most of these risks would be incurred regardless of whether the electricity generated were used domestically or sent abroad, so that the portion of such risks that could fairly be attributed to additional exports over regional transmission grids may be limited.

ENVIRONMENTAL BENEFITS OF THE POWER GRID IN NORTH AMERICA

Historically, there have been very substantial environmental benefits from the power grid in the western half of North America. Hydropower from southwestern Canada and northwestern United States, flowing over the Pacific Intertie, has displaced fossil-fuelled power in California and elsewhere, reducing atmospheric emissions. Looking forward, however, further enhancement of the power grid in western North America might well facilitate the displacement of gas-fired generation by coal-fired generation, causing atmospheric emissions to increase. This would depend on the extent to which coal-fired power remains cheaper than gas-fired power to produce.

The Pacific Northwest – Pacific Southwest Intertie has displaced substantial amounts of natural gas. For every year since 1986, there have been net transfers from the Pacific Northwest to California. The generating mix in the Western Systems Coordinating Council, to which California belongs, includes a major component of natural gas-fired capacity, with gas and a small amount of oil accounting for 22 percent of generation in 1989 and 23 percent in 1999. Since gas-fired plants have higher fuel (operating) costs than coal-fired, hydro or nuclear capacity, it is thus fair to assume that very nearly all of the hydropower imported into California over the Intertie displaces gas.

Table 17 indicates the Intertie's benefits in terms of reduced emissions of carbon dioxide. The Intertie's benefits from reduction of other air pollutants have also been substantial. The Northwest Power Planning Council has estimated the net transfer of power to the Southwest each year in average megawatts.[70] Multiplying this by 8,760 hours in a year, one obtains the amount of gas-fired generation displaced in gigawatt-hours. Multiplying again by 0.623 Mt of carbon dioxide emissions per GWh generated from gas, as indicated above, the result is million tonnes of estimated carbon dioxide emissions reductions. As seen from the table, net displacement of carbon dioxide over the 15-year period from 1986 through 2000 amounted to some 173 Mt. If the avoided emissions were valued at $20 per tonne of carbon dioxide, the value over the period would be about $3.5 billion.

Looking forward, the environmental impact of grid enhancements in the western United States would depend on future coal and gas prices. As described in the previous chapter, there are two views of how an enhanced grid might operate. If gas prices are much higher than coal prices, as assumed in an analysis performed for the Western Governors' Association, there is likely to be substantial displacement of gas by coal. This would bring sizeable savings in fuel costs but would also carry heavy environmental costs. If gas prices are more moderate, as assumed in an alternative analysis performed at Resources for the Future, switching between gas and coal is apt to be much more limited. This would mean smaller economic benefits but also lower environmental costs.

[70] Northwest Power Planning Council (2001), page 8.

Table 17 Carbon Dioxide Emissions Avoided on the Pacific NW - SW Intertie

Year	Average MW Transferred	Thousand GWh (TWh) Transferred	Mt Avoided CO_2 Emissions	Value of Avoided Emissions at $20/t
1986	3,155 MW	27.6 TWh	17.2 Mt	$344 million
1987	2,339 MW	20.5 TWh	12.8 Mt	$255 million
1988	1,379 MW	12.1 TWh	7.5 Mt	$151 million
1989	1,483 MW	13.0 TWh	8.1 Mt	$162 million
1990	2,826 MW	24.8 TWh	15.4 Mt	$308 million
1991	2,672 MW	23.4 TWh	14.6 Mt	$292 million
1992	889 MW	7.8 TWh	4.9 Mt	$97 million
1993	106 MW	0.9 TWh	0.6 Mt	$12 million
1994	306 MW	2.7 TWh	1.7 Mt	$33 million
1995	1,174 MW	10.3 TWh	6.4 Mt	$128 million
1996	3,788 MW	33.2 TWh	20.7 Mt	$413 million
1997	3,947 MW	34.6 TWh	21.5 Mt	$431 million
1998	2,204 MW	19.3 TWh	12.0 Mt	$241 million
1999	3,345 MW	29.3 TWh	18.3 Mt	$365 million
2000	2,019 MW	17.7 TWh	11.0 Mt	$220 million
Total	**31,632 MW**	**277.1 TWh**	**172.6 Mt**	**$3,453 million**

Source: Northwest Power Planning Council. Calculations by APERC.

Table 18 compares incremental power industry costs in the western United States, excluding and including environmental impacts, for both scenarios. In the WGA scenario, with relatively high gas prices, increased coal use would increase nitrogen oxide emissions by 183 thousand tonnes, sulphur dioxide emissions by 121 thousand tonnes, and carbon dioxide emissions by 52 million tonnes. In the RFF scenario, with relatively moderate gas prices, environmental impacts would be roughly one-tenth to one-fifth as large, with NOx emissions increasing by just 19 kt, SO_2 emissions by 25 kt and CO_2 emissions by 5 Mt. Assuming that unit costs of NOx and SO_2 emissions are as postulated in the WGA study and CO_2 emissions impose costs of $20 per tonne, the inclusion of environmental costs would cut the annual cost reduction in the WGA case nearly in half, to about $1.3 billion. If carbon dioxide emissions were valued at $45 per tonne, the cost reduction in the WGA case would vanish.[71]

Table 18 Two Views of Transmission Expansion in the Western United States (Costs in 2010 Excluding and Including Environmental Externalities)

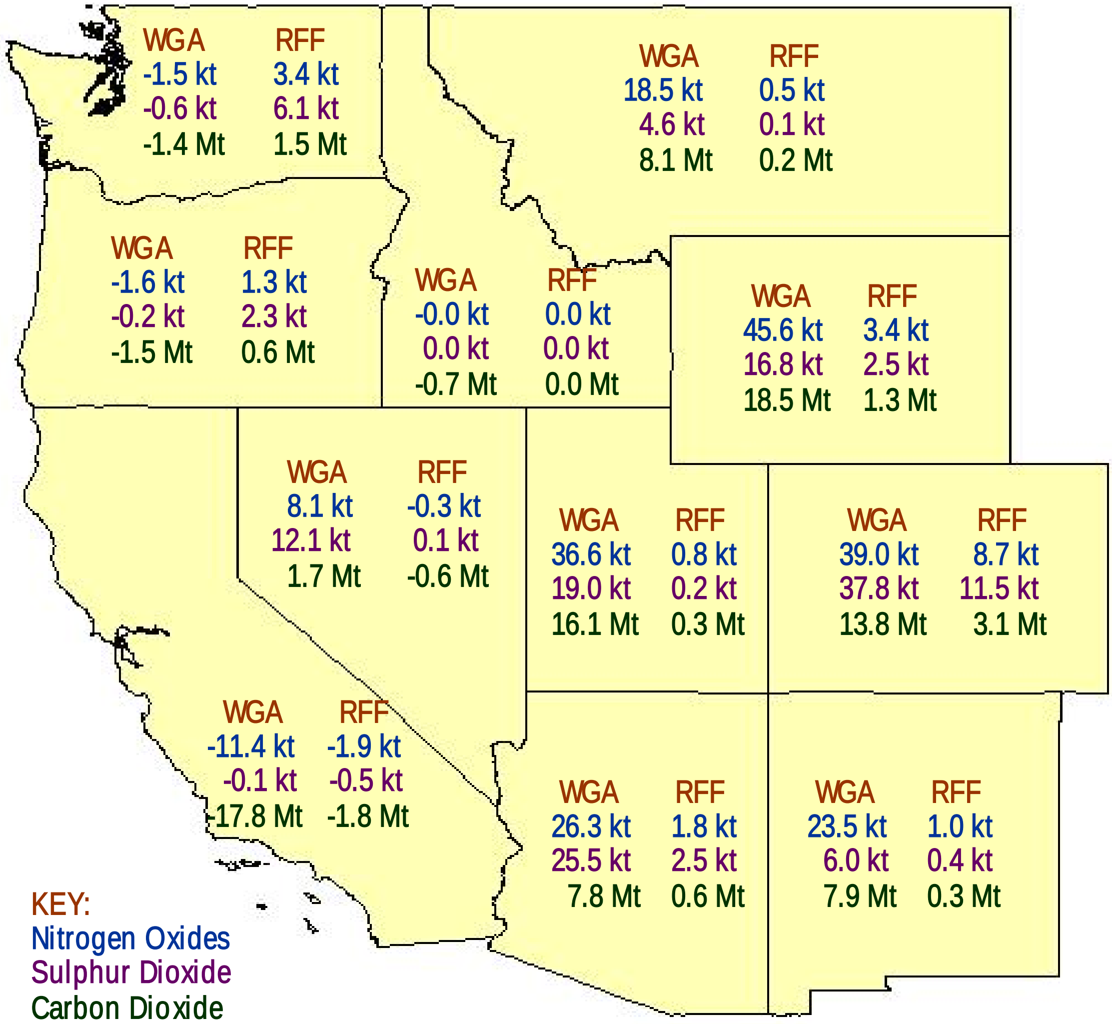
	Western Governors Association View			Resources for the Future View		
Cost Component (Million 1997 $)	Change Amount	Unit Value	Cost Change	Change Amount	Unit Value	Cost Change
Fuel, G & T	-$2,529	N/A	-$2,529	+$211	N/A	+$211
Nitrogen Oxides	183.1 kt	$142/tonne	+$26	18.8 kt	$142/tonne	+$3
Sulphur Dioxide	120.9 kt	$1,042/tonne	+$126	25.1 kt	$1,042/tonne	+$26
Carbon Dioxide	52.5 Mt	$20/tonne	+$1,050	5.5 Mt	$20/tonne	+$110
Total Cost			**-$1,327**			**+$350**

Sources: Transmission Working Group (2001). Bloyd (2004).

[71] Transmission Working Group (2001). Bloyd and others (2002). Bloyd (2004).

It may also be of interest to note that the regional distribution of environmental impacts from transmission grid expansion is likely to be quite uneven, as shown in Figure 31. In the WGA scenario, with high gas prices, there is substantial displacement of gas-fired electricity in the coastal states of California, Oregon and Washington by imported coal-fired electricity from other states, several of which are centres of coal production. Consequently, there is a noticeable decrease in NOx and SO_2 emissions in the coastal states (as gas-fired generation declines) and a much larger increase in these emissions from neighbouring states (as coal-fired generation increases). In the RFF scenario, with less displacement of gas by coal, the environmental effects are less pronounced.

Figure 31 Two Views of Transmission Expansion in Western United States (Change in Emissions of Nitrogen Oxides, Sulphur Dioxide and Carbon Dioxide)



Source: Bloyd (2004).

ENVIRONMENTAL BENEFITS OF A POWER GRID IN NORTHEAST ASIA

Northeast Asia has very large undeveloped resources of gas, hydropower, wind power and nuclear power, the greater use of any of which would bring real environmental benefits. These include gas reserves in Russia, hydropower resources in Russia and China, wind sites in China and probably elsewhere, and substantial further nuclear power development in Japan and Korea.

As shown in the table below, Russia has much larger proven natural gas reserves than either China or Japan, as well as substantially higher reserve-to-production ratios. Thus, gas production in Russia could be readily expanded to yield far greater exports of gas to China, Japan and Korea. While some of the expanded gas exports would probably take place through pipelines or LNG facilities, some might also occur as gas by wire, with gas-fired power plants in Russia sending extra electricity over a Northeast Asia power grid. However, the potential for expanded gas exports from Russia for power production must be viewed with caution, in light of the significant cost advantage currently enjoyed by coal-fired power in China and the slow growth of electricity demand in Japan. In the absence of a very sizeable environmental premium, on the order of US$20 per tonne of carbon dioxide, gas cannot easily compete with coal in most of China's power market.[72]

Table 19 Oil and Gas Reserves in Northeast Asia

Economy / Region	Gas Reserves (Proven)	Gas Reserves to Production Ratio	Oil Reserves (Proven)	Oil Reserves to Production Ratio
Russia	47.6 Tcm	83 x	7.7 Bt	19 x
East Siberia and Russian Far East	2.1 Tcm	256 x	1.6 Bt	1,044 x
China	1.4 Tcm	45.x	3.3 Bt	20 x
Japan	0.03 Tcm	62 x	0.0076 Bt	10 x

Sources: APERC (2000) and Institute of Energy Economics, Japan (2003).

In addition, both Russia and China have a great deal of potential to expand their production and exports of hydropower. Japan and Korea have significant hydro resources, but roughly two thirds of the technical potential of these resources has already been exploited. As a practical matter, in view of environmental and zoning considerations, little further exploitation of these resources is likely to be realised. But in Russia, only 10 percent of the hydropower potential has been exploited, with just 14 percent developed in East Siberia and 2 percent developed in the Far East. China, too, has exploited just 10 percent of its hydropower potential, with 13 percent developed in the North and 29 percent developed in the Northeast. So hydropower production in China and Russia could readily be expanded for additional power exports to other Asian economies.

Table 20 Hydropower Resources in Northeast Asia

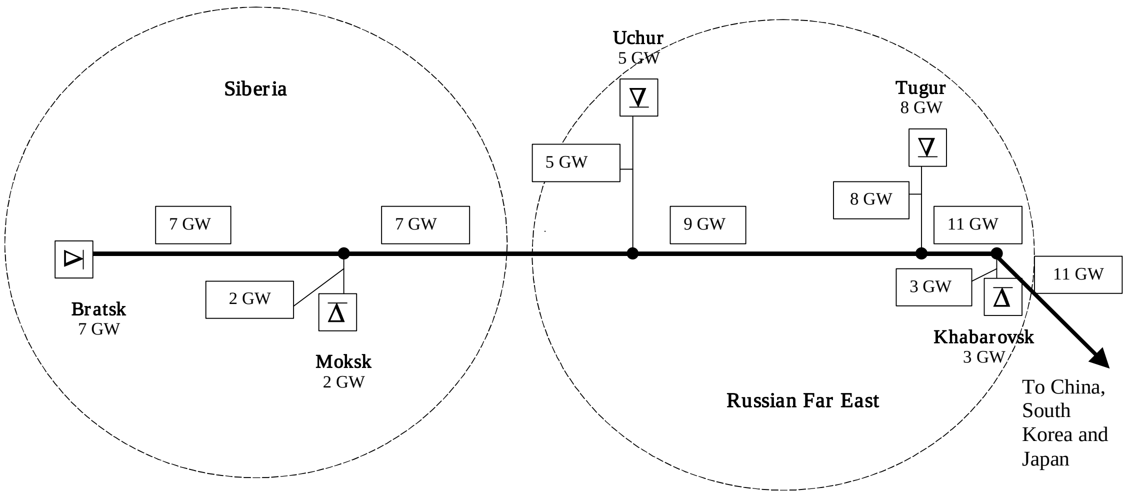
Economy / Region	Technical Potential for Hydropower	Hydropower Resources Developed as of 2000	Fraction of Hydropower Potential Exploited
Total Russia	1,670 TWh/year	168.4 TWh/year	10 percent
East Siberia	661 TWh/year	91.8 TWh/year	14 percent
Russian Far East	684 TWh/year	10.8 TWh/year	2 percent
Total China	1,923 TWh/year	188.0 TWh/year	10 percent
North China	23.2 TWh/year	3.1 TWh/year	13 percent
Northeast China	38.4 TWh/year	11.0 TWh/year	29 percent
Japan	34.2 GW	22.1 GW	65 percent
South Korea	7.6 TWh/year	5.2 TWh/year	68 percent

Source: APERC (2000). Overview of Potential Power Interconnections in the APEC Region.

[72] APERC (2004), pages 61-75.

Indeed, expansion of hydropower generation and associated electric transmission lines is already under serious consideration in Russia and is part of official long-term plans in China. The Russian Academy of Sciences has analysed a west-to-east power interconnection linking Eastern Siberia with the Russian Far East, as shown in the diagram below. This could make 11 GW of hydro and tidal power available for export, displacing some 14 million tonnes coal equivalent of fossil fuel and reducing carbon dioxide emissions by 30 million tonnes per year.[73] The State Grid Corporation of China expects to have 6 high-voltage DC transmission links in place by 2005 with a capacity of 12.6 GW, and plans to have 20 DC links by 2020 with a capacity of 60 GW. Much of this capacity will be used to transmit hydropower from west to east. For example, East China is to receive power over 1,300 km and 2,100 km lines from Xiangjiaba and Xiluodu hydro stations.[74]

Figure 32 Proposed Interconnection between East Siberia and Russian Far East



Source: Podkovalnikov (2004).

Since both China and Russia are contemplating major west-to-east links for transmission of hydropower, it may be interesting for future studies to examine whether north-south links between them would make sense. If hydro flows in China come earlier in the spring than hydro flows in Russia, where snow melts later, then north-south links could allow a sort of seasonal diversity exchange between the two west-east systems. Spare transmission capacity in Russia could help transmit Chinese hydropower earlier in the spring, while spare transmission capacity in China could help transmit Russian hydropower later in the spring. This could allow the economies to move the same amount of hydropower at lower cost, or else to move a greater amount of hydropower over the transmission lines available, augmenting the environmental benefits obtained at any given time.

Further, there are very substantial wind resources, in China and elsewhere in Northeast Asia, that are likely to require transmission grid development for delivery to urban markets. As noted by the President's Council of Advisors on Science and Technology in the United States, "China has some of the best wind-energy resources in the world. For example, good wind resources are available over about 80,000 km^2 of Inner Mongolia…. Wind farms based on the use of modern wind turbines in this region could provide about 1,800 TWh/year of electricity, which is 1.7 times the total rate of electricity generated from all sources in China in 1996…. There are reasonably good prospects that electricity produced via multi-gigawatt-scale baseload wind-energy projects in Inner Mongolia using modern wind turbines mass-produced in China and deployed in conjunction with compressed-air energy storage (CAES) could be competitive, without subsidy, with electricity from coal in northern China (produced in plants equipped with flue-gas desulfurization), when delivered to distant markets in large northern cities such as Beijing…" [75]

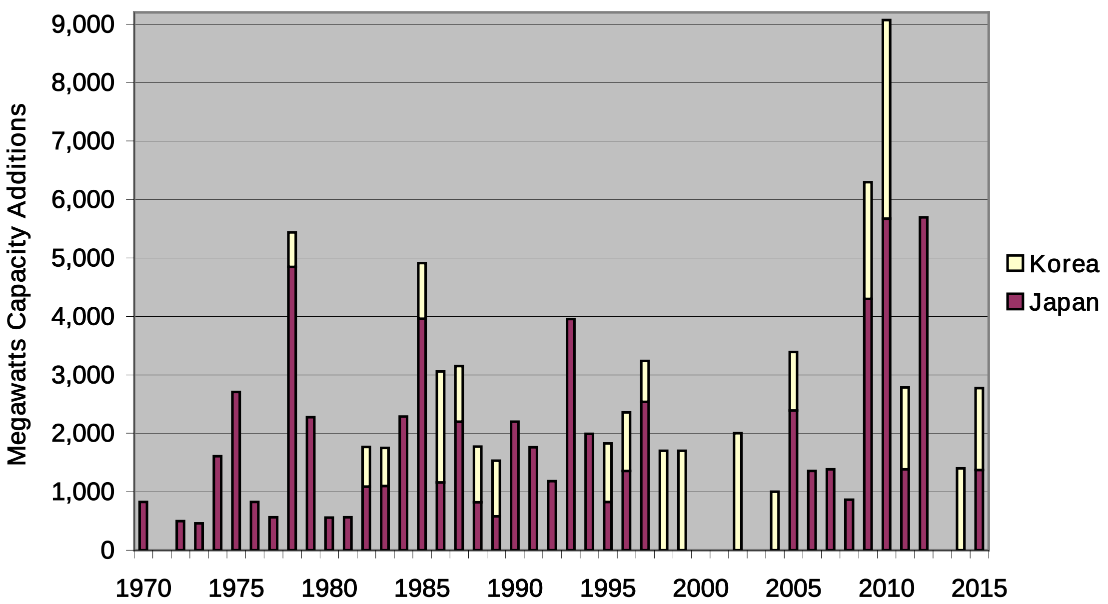
[73] Podkovalnikov (2004), pages 7-9. Belyaev and others (2003).

[74] Zhou - State Grid Corporation of China (2004).

[75] President's Council of Advisors on Science and Technology (2000), pages 5-7.

Beyond this, it can be noted that Japan and Korea continue to build and plan substantial amounts of nuclear generating capacity beyond that which is already in place. Over the twelve-year period from 2004 through 2015, Japan is planning to complete about 24 GW of new nuclear generating capacity, while Korea is planning to complete about 12 GW of such capacity. These would represent increments of over 50 percent above the 45 GW of nuclear capacity already in place in Japan and 70 percent above the 16 GW of such capacity in place in Korea.[76] While new nuclear plants are being built to serve domestic markets, a portion of their output might be available for export over a Northeast Asia power grid to Russia or northern China. Peak demand in those regions occurs during the winter, while peak demand in Japan and Korea occurs during the summer, allowing them to export electricity during the winter when Russia and China need it most.

Figure 33 Past and Projected Nuclear Capacity Additions in Japan and Korea



Source: IAEA, Japan Atomic Industrial Forum, Korea [name]

The amount of gas-fired, hydro, wind and nuclear power available for export would depend upon the degree to which load patterns in neighbouring economies are complementary, as well as the merit order in which power plants in each respective economy are dispatched. As shown in Figure 34, there is plenty of potential to displace emissions from gas- and coal-fired plants within each Northeast Asian economy, without the need for power exports over a regional power grid. In Russia, output from new gas-fired plants could displace generation from domestic coal-fired plants. New hydro facilities in Russia or China, or new nuclear plants in Japan or Korea, could also be used to displace gas or coal in internal markets without exports. So gas-fired, hydro, wind or nuclear plants would be used to displace less environmentally friendly options in neighbouring economies only insofar as their output were surplus to domestic needs at times when neighbours need it.

It follows that in order to evaluate the environmental benefits of a Northeast Asia power grid in a convincing way, it would be necessary for participating economies to share detailed information on their daily and seasonal load patterns, as well as the mix of plants from which loads are satisfied. Without such information, it would be hard for each economy to assess how much output from new gas-fired, hydro, wind or nuclear plants would be available from its neighbours. It would also be impossible to say which fuels would be displaced by power exports from such plants at different times. Consequently, it would be difficult to properly assess the cost savings or environmental savings of power flows between economies on a Northeast Asia grid. Yet there are good indications that the environmental benefits of a Northeast Asia power grid could be substantial.

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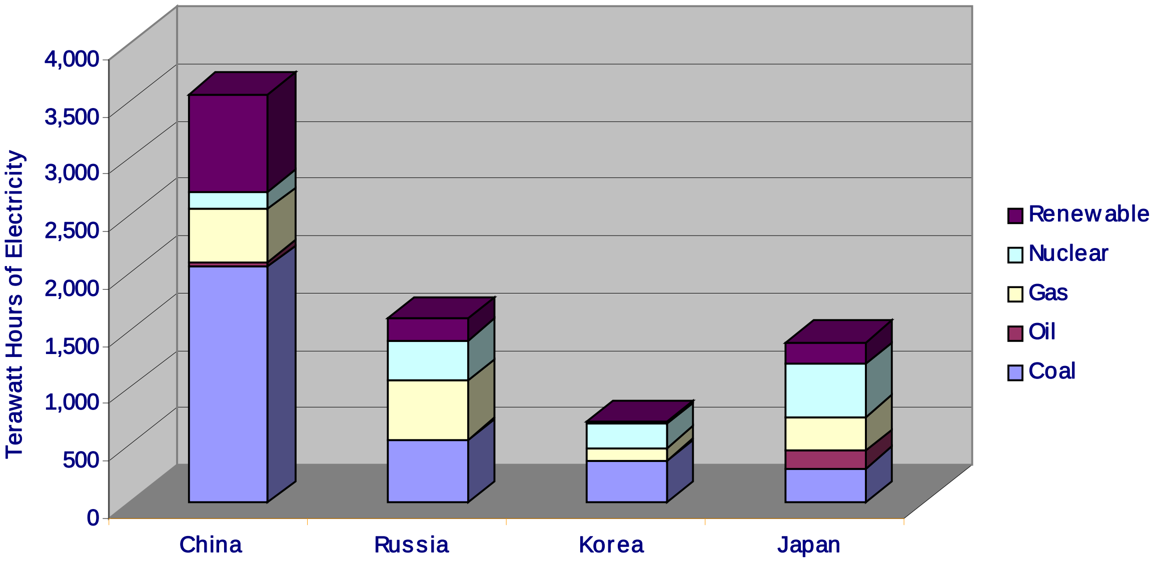
76 Japan data from Japan Atomic Industrial Forum. Korea data from Korea Hydro and Nuclear Power Company Ltd.

These should offer sufficient encouragement to neighbouring governments to justify their cooperation in a regional modelling effort that could come to more definitive results.

Figure 34 Northeast Asia Generating Mix in 2020 without a Power Grid

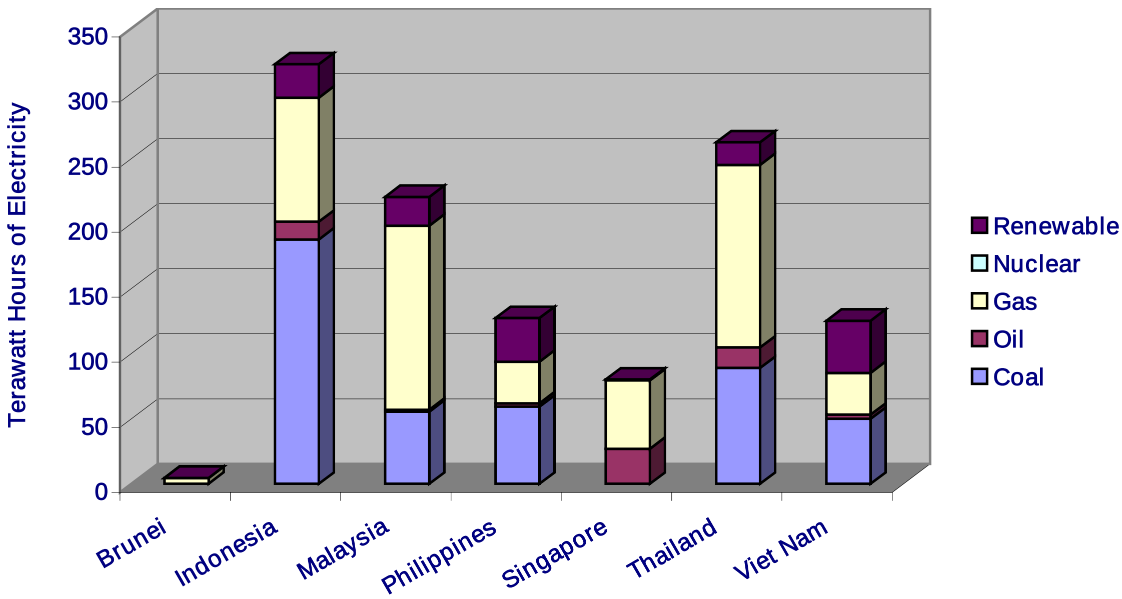


Source: APERC (2002). Energy Demand and Supply Outlook

ENVIRONMENTAL BENEFITS OF A POWER GRID IN SOUTHEAST ASIA

Indonesia, Malaysia and Brunei have large gas reserves, the exploitation of which might be accelerated if new power transmission lines were available and new gas-fired generating capacity were built to export power over the lines. A great deal of power in Southeast Asia is still generated from coal, as shown in Figure 35. Thus, accelerated gas development could have environmental benefits if gas were able to compete with coal for power production in some export markets.

Figure 35 Southeast Asia Generating Mix in 2020 without a Power Grid



Source: APERC (2002). Energy Demand and Supply Outlook

As shown in Table 21 below, the major gas producing economies of Brunei Darussalam and Indonesia are projected to have ample reserve margins in 2020. These seem likely to more than satisfy the 15 percent reserve margin criteria in Sumatra and West Kalimantan, as well as easily to allow the satisfaction of the N-2 reliability criteria in Brunei and Sabah/Sarawak. Lao PDR, potentially a major hydropower producer, also appears to have adequate reserve margins, well in excess of its 15 percent planning criterion. In all of these cases, therefore, it is reasonable to suppose that substantial amounts of power could be available for export in the future.

Table 21 Projected Power System Reserve Margins in ASEAN Economies in 2020

Economy	Installed Capacity	Peak Power Demand	Reserve Margin
Brunei D.	1,472 MW	957 MW	53.8 percent
Cambodia	1,125 MW	1,205 MW	(-6.7) percent
Indonesia	81,662 MW	64,225 MW	27.1 percent
Lao PDR	1,082 MW	818 MW	32.3 percent
Philippines	40,654 MW	32,445 MW	25.3 percent
Singapore	13,739 MW	11,370 MW	20.8 percent
Thailand	53,890 MW	49,975 MW	7.8 percent
Viet Nam	38,570 MW	32,376 MW	19.1 percent

Source: Balce, Tjaroko and Zamora (2002). ASEAN data were not available for Malaysia or Myanmar.

Despite the apparent long-term potential for additional gas and hydro to displace coal in the Southeast Asia generating mix, the environmental impact of the eleven power links identified in the ASEAN Interconnection Master Plan Study would be modestly negative. As shown in Table 22, coal-fired generation in 2020 would increase by roughly 2 percent as a result of the power links, while gas-fired generation would decline by nearly 2 percent. As a consequence, applying the emissions factors in Table 14, carbon dioxide emissions would rise by 0.5 percent, sulphur dioxide emissions by 1.6 percent and nitrogen oxide emissions by 2.0 percent, as shown in Table 23.

Table 22 Projected Generating Mix in Southeast Asia in 2020 with and without Eleven Power Links in the ASEAN Interconnection Master Plan Study

Type of Generation	Without AIMS Power Links	With AIMS Power Links
Coal or Lignite	497.4 TWh (43.0%)	507.2 TWh (43.8%)
Natural Gas	494.4 TWh (42.7%)	486.2 TWh (42.0%)
Hydropower	148.4 TWh (12.8%)	147.1 TWh (12.7%)
Diesel or Oil	9.8 TWh (0.9%)	10.1 TWh (0.9%)
Nuclear and Other	7.9 TWh (0.7%)	7.3 TWh (0.6%)
Total	1,157.9 TWh (100%)	1,157.9 TWh (100%)

Source: ASEAN Interconnection Master Plan Study (2003). Hydropower includes pumped storage.

Table 23 Environmental Emissions in 2020 with and without AIMS Power Links

Type of Emissions	Without AIMS Power Links	With AIMS Power Links
Global Warming (CO_2)	775 million tonnes	779 million tonnes
Ozone Depletion (CFC_{11})	5.83 tonnes	5.94 tonnes
Acidification (SOx)	1,660 thousand tonnes	1,686 thousand tonnes
Acidification (NOx)	680 thousand tonnes	693 thousand tonnes
Eutrophication (phosphate)	190 thousand tonnes	191 thousand tonnes

In the Greater Mekong Subregion, in contrast, enhanced interconnections should bring substantial environmental benefits through the displacement of coal-fired power by hydropower. As described earlier, scenario A includes all proposed transmission grid enhancements for the region through 2020, while scenario B includes all cost-effective enhancements and scenario C includes all cost-effective enhancements except for links between Myanmar and Thailand. In each case, as shown in Table 24, the transmission grid enhancements cause the generating share of hydropower to rise from 23 percent to between 28 percent and 32 percent. At the same time, the generating share of coal declines from 33 percent to between 24 percent and 30 percent.

Table 24 Projected Generating Mix in the Greater Mekong Subregion in 2020

Type of Generation	Baseline	Scenario A	Scenario B	Scenario C
Coal or Lignite	210.0 TWh (33%)	150.4 TWh (24%)	163.0 TWh (26%)	188.4 TWh (30%)
Natural Gas	261.2 TWh (42%)	264.4 TWh (42%)	259.3 TWh (41%)	257.0 TWh (41%)
Hydropower	147.0 TWh (23%)	203.6 TWh (32%)	196.0 TWh (31%)	173.2 TWh (28%)
Nuclear and Other	9.6 TWh (1.5%)	9.6 TWh (1.5%)	9.6 TWh (1.5%)	9.6 TWh (1.5%)
Total	628 TWh (100%)	628 TWh (100%)	628 TWh (100%)	628 TWh (100%)

Source: Doorman and others (2004).

As a result, carbon dioxide emissions decline by 250 million tonnes to 475 million tonnes over the 15-year projection period. Assuming a discount rate of 12 percent and a very conservative value of US$5 per tonne of carbon, the value of reduced emissions would be US$288 million to $485 million, as much as doubling the overall economic benefits of the interconnections. Assuming a carbon value of US$20 per tonne, the value of reduced emissions could be far greater than the direct benefits in terms of reduced generating and transmission costs. If pollutants such as sulphur dioxide and nitrogen oxides were considered, the benefits would be even greater.[77]

Table 25 Direct Cost Savings and Value of Carbon Dioxide Emissions Reductions from Enhanced Power Interconnections in the Greater Mekong Subregion

Cost Savings	Baseline	Scenario A	Scenario B	Scenario C
Direct Cost Savings	0	$454 million	$914 million	$645 million
CO_2 at $5 per tonne	0	$485 million	$410 million	$288 million
CO_2 at $20 per tonne	0	$1,940 million	$1,640 million	$1,152 million

Source: Doorman and others (2004)

CONCLUDING OBSERVATIONS

The environmental benefits of power grids depend on how they change the mix of fuels from which electricity is generated. The mix of fuels, in turn, depends on the relative costs of generating power from them. In western North America and Southeast Asia as a whole, grid enhancements may increase emissions of atmospheric pollutants by assisting the displacement of gas-fired generation by less costly coal-fired generation. On the other hand, in the Mekong subregion of Southeast Asia and in Northeast Asia, grid enhancements should reduce emissions of atmospheric pollutants substantially by allowing substitution of hydropower for fossil-fuelled power. In Northeast Asia, grid enhancements may also limit atmospheric pollutant emissions by allowing the displacement of fossil-fuelled electricity generation by nuclear power plant projects.

[77] Doorman and others (2004). At a 10 percent discount rate, the net present value of carbon emission reductions over the projection period increases by about a quarter, to $617 million in scenario A, $520 million in scenario B and $359 million in scenario C for each assumed valuation increment of $5 per tonne of carbon.

STREAMLINING REGULATION TO FACILITATE POWER GRIDS

INTRODUCTION

A key obstacle to the extension or expansion of power grids is resistance to their construction by those who own the land on the path of prospective transmission lines. The "not in my backyard" syndrome, commonly known as "NIMBY," is widespread and well documented. Since new transmission lines that cover any considerable distance must obtain zoning approvals from numerous local authorities along their path, zoning and environmental approvals from various state or provincial authorities, and often regulatory approvals from national governments as well, there is ample opportunity for the forces of opposition to delay or even block their construction.

Indeed, there may be quite legitimate reasons why a particular transmission line should not be built in a particular place. On certain routes, there may be notably adverse effects on scenic views, wildlife habitats, economic activity and human settlement. On alternative routes nearby, the adverse effects may be much less pronounced. Regulators will need to be convinced that any adverse effects of new transmission lines are acceptable, that the routes chosen for the lines minimise the potential adverse effects, and that the potential adverse effects are outweighed by the potential benefits. Thus, transmission planners need to consider several different options for expanding grids in any given direction, perform detailed economic and environmental analyses of the options, and explain to regulators why their preferred expansion options are desirable.

But even if a proposed new power line has clear net benefits and is obviously superior to alternative options, its construction may be blocked because its benefits are not evenly distributed. A new transmission line may boost revenues to power producers at either end and lower costs to consumers at either end, without providing any benefits on the path through which it runs. Thus, some local, state and provincial authorities may vehemently oppose a new power line while others strongly support it. In such cases, higher authorities may have to reconcile the differences and decide whether to insist upon construction of new lines that would benefit the economy as a whole.

A careful consideration of alternatives need not imply that transmission grid enhancements with large potential benefits be delayed indefinitely. Procedures are available to accommodate necessary zoning and environmental reviews in a more systematic and coherent fashion. For example, various regulatory reviews can be undertaken in parallel rather than in sequence. This chapter reviews some of the methods that APEC economies have tried or proposed to streamline zoning and environmental regulations and reach decisions on power line expansion more quickly.

INITIATIVES TO STREAMLINE REGULATION IN NORTH AMERICA

Siting new electric transmission lines is especially complex in the United States because of the multiplicity of authorities that must approve them. For high-voltage, long-distance lines, the authorities typically include numerous local governments, several state governments, and a variety of federal agencies. In the West, approval may also be required from sovereign tribes whose land the lines would cross. Federal agencies involved may include the US Forest Service, the National Park Service, the US Army Corps of Engineers, and the US Environmental Protection Agency as well as the Federal Energy Regulatory Commission (FERC), all of which have different interests.

Yet the main responsibility for siting electric transmission lines remains with the states, except in areas served by a federal power marketing administration or the Tennessee Valley authority. The utility or other entity that wishes to build a new line makes a formal proposal to a state siting authority, typically the regulatory utility commission. In order to obtain a certificate of public need that allows the line to be built, the applicant must demonstrate to the siting authority that the line serves a legitimate public need. The public need is variously defined but typically includes criteria such as whether the project is needed to maintain the reliability of the power supply system, to carry on regional electricity trade, or to connect a state-approved generating facility to the grid.[78]

In this context, it seems apparent that efforts to streamline siting of transmission lines in the United States must focus on the states. An expert study sponsored by the US Department of Energy (DOE) suggested a number of practical options to improve the state transmission siting process:[79]

- Promote or require an open, transparent transmission planning process.
- Require project applications to address a broad range of alternatives.
- Review approval criteria and update if necessary, considering whether the requirements of commerce (benefits of trade) should be recognised explicitly in the state siting authority's determination of need for transmission capacity.
- Modify state law if necessary to enable siting authorities to take account of out-of-state benefits when considering the merits of a transmission siting proposal.
- Adopt a "one-stop" siting process, with all state reviews consolidated in the siting authority, allowing local and county governments to direct transmission facilities to preferred locations but taking away their ability to reject such facilities.
- Set a maximum time limit (12 or 18 months) for review by state or local agencies.
- State clearly what materials must be included in an application, and refuse to initate a review until an application is complete.
- Promote use by applicants of both deterministic and probabilistic planning methods.
- Promote more consistent use of "rolled in" and "cost causation" approaches to recovering costs of grid-related investments to allow fair comparison of alternatives.

In the study's view, an ***open and transparent planning process*** is particularly important in securing public support and regulatory approval for new transmission facilities. Such a process would solicit the views of all interested parties on how best to address a specific transmission need. The process would include "regular reports to the public about the state of the transmission grid and its expected needs" to facilitate "discussions about how to addressing growing concerns." Such discussions, the study notes, "can be particularly productive if they involve affected parties and all relevant information is available to anyone who cares to look for it." With an open process, all parties are likely to feel that their interests have been respected and considered. Moreover, such a process provides information to applicants that lets them suit proposals to a broader spectrum of interests before they are formally submitted and thus makes proposals more likely to be approved.[80]

The presentation of a ***broad range of alternatives*** is also considered very important. "A proposal that presents and compares alternatives shows that the proponent is focused on meeting a system need in the best way, not on getting a particular project built. Addressing alternatives shows the applicant's confidence that the proposal represents the best approach to meeting a system need. This approach can be aided by undertaking an open planning process once a need has been recognized but before a solution is selected." The public can then "be engaged … to assist the transmission company in combining its own and public interest priorities in the decision process."[81]

Time limits can be helpful for pushing regulatory processes along and making it easier to obtain financing for needed new transmission lines. Applicants may be reluctant to devote the resources to developing a proposal and obtaining approvals for it if they are unsure they will be able to obtain financing. But financial institutions may be unwilling to commit capital to a project if they do not know when construction is likely to begin or be completed. Reasonable time limits can help ensure that this financial dilemma is kept to reasonable proportions. On the other hand, the

[78] Meyer and Sedano (2002), pages E-3 through E-5.

[79] Ibid., pages E-45 and E-46.

[80] Ibid., pages E-11 and E-33.

[81] Ibid., pages E-11 and E-32.

study finds, "the time allowed must be sufficient for a review that will meet public expectations for thoroughness and fairness. A very tight time limit can too frequently put the authority in the difficult position of nearing the deadline with inadequate evidence to find in favor of a project."[82]

The National Transmission Grid Study strongly advocated giving the FERC backup authority to authorise required transmission lines in the event that state authorities fail to do so within a specified period of time: "Federal regulators should actively support and defer to … state and regional siting and permitting processes. However, since new regional transmission facilities will typically span or impact multi-state areas that seldom align with the political boundaries of states, FERC must have appropriate backstop authority to ensure that the public interest is served…. When state and regional processes determine that construction of transmission facilities is needed … yet are unable to site or permit them in a timely fashion, FERC must be able to grant designated entities the right of eminent domain to acquire property for rights-of-way." [83]

Such federal backup siting authority was included in legislation proposed in 2001 by Senator Bingaman, Chairman of the Senate Energy and Natural Resources Committee. The idea was supported by investor-owned electric utilities through the Edison Electric Institute and by small business and residential consumers through the Electric Consumers Alliance. However, it was deleted from subsequent versions of energy legislation considered by the Congress, following strenuous objections from the National Governors Association, the Council of State Governments, and national associations of counties, towns and townships, state energy officials, state utility consumer advocates, and (state) regulatory utility commissioners.[84] In view of the strong opposition expressed by all facets of state and local government, it seems clear that backup transmission line siting authority for the federal government will be politically difficult or impossible to obtain. On the other hand, states themselves may be willing to incorporate deadlines into their siting processes.

Regional planning bodies are also an essential component of proposals for regulatory streamlining. Even if states streamlined their siting processes in the ways suggested, there would remain the need to better coordinate regulatory approvals for regional power lines that cross several states. For this purpose, the Task Force on Electricity Infrastructure that was established by the National Governors Association in 2001 has recommended the formation or empowerment of multi-state entities (MSEs). Each MSE would reflect the boundaries of a regional electricity market and would be established through a memorandum of understanding between state governors, federal land management agencies, federal public power authorities, tribal authorities, and border countries. The objective would be a "one-stop" application process for interstate lines, to "consolidate and harmonize, to the greatest degree possible, all application procedures of relevant state and federal agencies." Such a process could be implemented through an interstate protocol, which would describe how the states will coordinate their reviews of transmission applications, establish timelines for review and decisions by each state, and provide guidelines for sharing information. [85]

The MSEs would work closely with the Regional Transmission Organisations (RTOs) that the Federal Energy Regulatory Commission has been establishing. The RTO in each region would have principal responsibility for transmission planning, while the states would retain authority to approve or deny the construction of facilities proposed in the RTO plan. To make things go more smoothly, the MSE would provide the RTO with transmission planning guidelines its participants have agreed. In addition, the MSE would establish procedures for exchanging information with the RTO on which potential transmission corridors are seen as preferred or problematical. For any given interstate transmission project proposed in an RTO plan, a project team would be formed of all affected states. The project team would issue or deny a "regional need finding" for all or part of the RTO plan. Once such a regional need finding was issued, any transmission line applications consistent with the plan would be exempt from state-level need certification processes.[86]

[82] Ibid., pages E29 and E-30.
[83] US Department of Energy (2002), page 53.
[84] Meyer and Sedano (2002), pages E-16 and E-28.
[85] National Governors Association, Task Force on Electricity Infrastructure (2002), pages 10 and 21.
[86] Ibid., page 10.

A kind of MSE was in fact formed for the very large Western Interconnection in June 2002. It was created through a protocol signed by the Western Governors Association and the federal agencies responsible for energy, agriculture and the interior. It provides for collaborative review of interstate transmission line proposals without preempting existing authorities of any state or agency. Project teams are designated to develop information that will allow cooperative decisions on the need for lines, and the information is provided transparently to all participants through common records. Environmental reviews are handled jointly, and regulatory timelines are coordinated. The stated objectives of the coordinated joint review process are as follows:

- "Create an efficient environmental review process that results in documents that can be shared and used by all entities with jurisdiction in the siting and permitting process.
- "Establish and periodically review joint time lines for the conduct and timely completion of review and regulatory decision-making.
- "Establish a common understanding of the informational needs, regulatory requirements, and public interest issues prior to the environmental review proceeding.
- "Eliminate duplication of agency pre-application, scoping, and permit review meetings among affected state, local, federal and tribal authorities.
- "Create a transparent streamlined review process that is structured, user friendly and predictable.
- "Facilitate early notification and sharing of information among affected states, local governments, federal agencies, tribal governments and the project sponsors.
- "Preserve and protect authority of each affected state, local, government, tribal government, and federal agency."[87]

Federal agencies could also help to streamline the transmission planning process by better coordinating their reviews. The DOE expert study on transmission siting and permitting cites four main complaints about reviews of transmission proposals by federal land management agencies:

- There is often inconsistency within an agency in the ways local or regional land managers review transmission projects.
- When two or more federal agencies are involved, there is frequently inadequate communication and coordination between them.
- Review of transmission proposals is not the primary mission of the agency.
- Federal agencies often wait to conduct their review until state reviews are completed and a final route has been selected, so a federal agency may require a route change that necessitates further costly and time-consuming review by state regulators.[88]

Several options are available to address these issues. The federal review process could be centralised, with interagency staff groups to work jointly on reviewing transmission proposals. A memorandum of understanding could be signed in which all participating agencies agree to complete project reviews in a timely fashion. For any given transmission proposal, a lead agency could be given jurisdiction over all federal matters affected by the proposal; however, one federal agency may be very reluctant to give jurisdiction to another with respect to land use within its customary domain. More practically, the FERC could be designated as the lead agency for coordinating all federal reviews of proposed transmission facilities, with other agencies retaining their existing authorities. Since FERC is already experienced in economic and environmental review of energy projects and has an institutional reason to press for good coordination to obtain transmission lines seen by RTOs as needed for economic trade, this could be an excellent option.[89]

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[87] Western Governors Association and others (2002). Larson (2002), slides 15, 17, 19-20.

[88] Meyer and Sedano (2002), pages E-36 and E-37.

[89] Ibid., pages E-39 and E-40.

INITIATIVES TO STREAMLINE REGULATION IN NORTHEAST ASIA

Korea presents an interesting case of measures to streamline regulatory approvals for transmission lines while respecting the interests of all the parties affected. To streamline the process of obtaining approval for transmission line construction, the Korean government passed an Act on Special Cases Concerning Electric Source Development (ASCESD). The ASCESD supersedes other laws and regulations so that transmission line builders can obtain all approvals required in a one-stop process.[90] The ASCESD process has several distinct components or phases, which may be termed survey, selection, documentation, and reporting and compliance:

Survey: In the survey phase, proposed transmission line routes are investigated with respect to anticipated construction costs, environmental impacts, alternative plans for use of the land, and difficulties in purchasing the land.

Selection: In the selection phase, proposed routes are screened according to construction cost, environmental impact, feasibility of securing rights of way, and opinions of provincial administrative bodies and public, in order to select the route which is preferred.

Documentation: In the documentation phase, a detailed plan is prepared for transmission line construction. The plan includes a summary of electricity supply facilities involved, their location and the amount of area they are to occupy, the expected period of construction, and projected costs and sources of funding. It also indicates public facilities to be installed as part of the project and potential cost sharing arrangements for such facilities, expected impacts on national environmental preservation efforts, and other matters related to electric resource development as determined by presidential decree. An Environmental Investigation or Environmental Impact Statement is required (the latter for transmission lines with ratings of 345 kV and above and lengths of 10 km or greater, as well as outdoor 765 kV substations), covering three areas:

- Natural environment: Impacts on climate, topography, land and marine ecology, water resources and irrigation, as well as measures to minimize topographical or geological effects of transmission tower construction.
- Residential environment: Impacts on land use, air quality, noise and odors, water quality, soil, waste and access to light, as well as intended measures to mitigate such impacts.
- Socioeconomic environment: Impacts on population and on residential, industrial, public and educational facilities, on traffic, on cultural properties, as well as measures to reduce these impacts such as moving occupants of residences along the transmission line path, controlling increased traffic, and conserving culturally important sites or artifacts.

Permission: In the permission phase, builders obtain approval for their plan from local administrative bodies and government ministries according to a three-stage process:

- Local consultation: Builders discuss their plan for transmission line construction with local administrative bodies to iron out potential conflicts with plans for urban development projects, roads, industrial complexes, housing areas, cultural asset preservation, public water reclamation, farmland use, and forestry conservation. Builders then revise their plan as appropriate and submit it to the Ministry of Commerce, Industry and Energy (MOCIE).
- Ministerial consultation: Other ministries and provincial governments inform MOCIE of conditions they would attach to design or construction of the line, MOCIE relates the conditions to the builders, and builders inform MOCIE of measures they intend to take to meet the conditions. Ministries consulted include those in charge of finance and economy, national defence, government administration, science and technology, agriculture and forestry, information and communication, construction and transportation, maritime affairs and fisheries, and railroads.

[90] Text summarises relevant portions of Suhmoon and Hwang (2003).

- *Decision:* MOCIE analyses the plan, conditions and measures and submits the plan to the Electric Power Source Development Promotion Committee if it finds no serious outstanding disagreements between the parties. The Committee, which has two members from MOCIE and one from each of twelve ministries, decides whether the plan should be approved, modified or cancelled. MOCIE notifies stakeholders of the Committee's decision.

Reporting and Compliance: Transmission line builders are required to carry out or adhere to any conditions on construction imposed by provincial governments, ministries, or the Electric Power Source Development Promotion Committee, as well as to report annually on the status of these conditions. If a party finds that one of its conditions has been seriously neglected and the builder does not respond to its complaint, it can halt construction until the condition is met.

CONCLUDING OBSERVATIONS

While it might seem counter-intuitive, an open and transparent planning process, with consideration of a broad range of alternatives and clear requirements for documenting the impacts of each alternative, is key to ensuring that needed electric transmission lines can be built within a reasonable period of time. Because such a process involves political and analytic inputs from many people and organisations, it is more complex and requires more effort than a simple process in which a single alternative is considered by a limited group of experts. Yet paradoxically, an open process is more expeditious, because it allows all views and options to be considered and thereby builds the sort of consensus that allows new lines to go ahead without legal or political challenges.

The broad outlines of a successful streamlined planning process for transmission enhancements appear to be similar regardless of location. Several alternatives should be proposed and screened for each perceived transmission need. All interested parties should be consulted, including not those who are proposing the new lines but also local officials and the general public. Analyses of economic and environmental impacts should be made available for all to consider. Institutions should be put in place to ensure that all parties live up to their commitments. Finally, a regional planning body, which was earlier noted to be of value for reaching consensus on which transmission links are most economically worthwhile, can also be extremely useful for coordinating the approval processes for chosen grid enhancements in neighbouring states or economies.

HARMONISING LAWS AND RULES TO BOOST ELECTRICITY TRADE

INTRODUCTION

With respect to power trade among different economies, a wide variety of issues arise from differences in legal systems and economic and trade rules. If these issues are not resolved by harmonising laws and rules to a significant degree, the conditions for electricity trade will often be unfavourable. In that case, many of the potential benefits of grid interconnections will not be achievable, and incentives for expanding power grids across borders will thus be sharply limited.

Many of the issues might be regarded as specifically trade-related. If economies participating in a power grid have different taxes and customs duties on power imports or exports, the terms of power trade among them will be unequal. If licenses granted to electricity traders in one economy are not reciprocally recognised by others, trade will be hindered. If the free flow of funds between participating economies is restricted, the desire of market players to trade power will be curtailed.

Other issues are of a more general legal nature, often with significant social dimensions. Guidelines to protect the confidentiality of contracts and other documents, if lacking in certain economies, may discourage power trade with them. Similarly, if contracts are not enforceable in an economy, or if conditions for expropriation of property are not strictly limited by its courts, very few market players will wish to risk trading with entities in it. Furthermore, if some economies lack adequate laws regarding labour conditions, product safety, and consumer protection, others may be reluctant to trade with them, not only on social or moral grounds but also because the failure to incur the costs of providing for them may constitute an unfair trade advantage.

Fortunately, a number of existing trade agreements have dealt with such issues successfully. A leading example is provided by the North American Free Trade Agreement (NAFTA), Columbia River Treaty and other agreements involving the United States and Canada, which have led to active power trade between them. In addition, the Association of South East Asian Nations (ASEAN) has systematically analysed the differences in economic rules among its participants and is considering ways of harmonising them to promote a Southeast Asian power grid. This chapter briefly describes the crux of each issue and the methods used or proposed to deal with it.

BOOSTING POWER TRADE THROUGH HARMONISED RULES IN SOUTHEAST ASIA

The ASEAN Interconnection Master Plan Study identifies several regulatory and commercial differences that "create barriers to interconnection." It also has a matrix describing where each ASEAN economy stands on each of the issues identified. Based upon information provided by the participating economies, it suggests ways of harmonising the differences to lower the barriers.[91]

Four of the regulatory issues raised in the AIMS report relate to the **ability** to trade power:

- ***Licensing:*** In order for cross-border trade to take place, each interconnected economy must allow entities operating in other interconnected economies to participate in such trade. In some economies, the government grants an exclusive license for power imports and exports to a vertically integrated utility with a monopoly on electricity transmission. Examples include the Electricity Generating Authority of Thailand (EGAT) and Malaysia's Tenaga Nasional Berhad (TNB). In such cases, foreign power producers can export their electricity only through the domestic monopoly transmission company. In other economies, such as Cambodia, Indonesia, and Viet Nam, participation of foreign entities in electricity trade is

[91] Information in this section is extracted from AIMS Working Group (2003), chapter 13 and appendix 18.

authorised through bilateral agreements between governments. In these cases, trade may be implemented through power purchase agreements (PPAs). The AIMS report recommends that special licenses be issued by each country on a reciprocal, non-discriminatory basis to participants in cross-border power trade.

- *Supply to customers:* Cross-border trade may be facilitated if entities in one economy are allowed to supply power to customers in another economy. "Cross-economy" trade, in which power trade occurs between two economies but the power passes through transmission lines in a third economy, can also be facilitated if entities in one economy are allowed to supply power to customers in another. As with cross-border trade between two power producers, Thailand's EGAT has a license to engage in trade involving power imports to a domestic customer or power exports to a foreign customer. Again as with cross-border trade between power producers, Indonesia and Viet Nam authorise trade between generators and customers through bilateral agreements between governments. In Malaysia and Thailand, cross-border trade involving a generator and a final customer requires a specific license. The AIMS report states that it is sufficient for ASEAN countries to have a licensing regime that allows cross-border and cross-economy transactions.
- *Free flow of funds:* In order for cross-border power trade to be commercially feasible, there must be a free flow of funds so that the income generated from trade can be repatriated. In fact, it appears that the free flow of funds is allowed by all ASEAN economies, so this factor does not present an impediment to trade.
- *Import and export restrictions:* The purchase and sale of electricity across borders can be limited through regulatory restrictions on the allowable amount of trade in power (megawatts) or energy (gigawatt-hours), technical limits on available transmission capacity, and technical requirements like sharing of ancillary services. In fact, ASEAN members have no regulatory restrictions on imports or exports of electricity, mainly because most economies do not define electricity as a commodity. To better deal with technical limits and requirements, the AIMS report suggests that economies "manage any restrictions in order to encourage import and export." This may entail bilateral negotiations or agreement on technical standards.

Table 26 Agreements to Avoid Double Taxation Among ASEAN Economies in 2003

	Brunei	Cambodia	Indonesia	Lao PDR	Malaysia	Myanmar	Philippines	Singapore	Thailand	Viet Nam
Brunei		O	P	O	P	O	O	O	O	O
Cambodia	O		O	O	O	O	O	O	O	O
Indonesia	P	O		O	X	O	X	X	X	X
Lao PDR	O	O	O		O	O	O	O	X	X
Malaysia	P	O	X	O		X	X	X	X	X
Myanmar	O	O	O	O	X		O	O	O	P
Philippines	O	O	X	O	X	O		X	X	P
Singapore	O	O	X	O	X	O	X		X	X
Thailand	O	O	X	X	X	O	X	X		X
Viet Nam	O	O	X	X	X	P	P	X	X	

Source: ASEAN Interconnection Master Plan Study (2003). Agreement Key: X = Existing. P = Pending. O = None.

Another three regulatory issues identified in the AIMS report relate to **taxation** of power trade:

- *Double taxation:* Double taxation of revenues from power trade could limit cost-saving transactions by subjecting them to extra tax burdens. Such double taxation may occur on business profits, dividends, interests and royalties. In fact, as shown in Table 26, several ASEAN economies have bilateral agreements to avoid double taxation among themselves. These include Indonesia, Malaysia, Philippines, Singapore, Thailand and Viet Nam. Other ASEAN economies, such as Brunei Darussalam, Cambodia, Lao PDR and Myanmar, are just beginning to negotiate agreements to avoid double taxation. The AIMS report encourages all ASEAN member economies to have double taxation agreements with each other.

- *Corporate taxation:* Ambiguity as to whether corporate tax will be imposed on revenue from cross-border electricity trade may limit such trade by exposing it to additional commercial risks. In fact, no corporate tax is specifically imposed on revenue from cross-border electricity trade in most ASEAN member economies. However, the AIMS report suggests that it may be advantageous for economies to establish a common policy regarding whether corporate income tax should be levied on cross-border power trade, in order to reduce uncertainty for investors.

- *Customs duties:* Customs duties, like taxes, can limit cost-saving electricity trade by raising its financial burden on participants. In reality, most ASEAN economies have no customs duties on electricity imports and exports because electricity is not categorised as a commodity. However, Cambodia has imposed value added tax and customs duties on power imports that recently began from Viet Nam. As with corporate taxation, the AIMS report recommends that economies consider establishing a common policy on whether customs duties should be imposed on cross-border power trade, in order to create greater certainty for investors.

A further two regulatory issues in the AIMS report relate to the **rule of law**:

- *Expropriation of assets:* Companies will naturally be reluctant to invest in cross-border transmission facilities if they fear that their assets could be expropriated. Several economies, including Cambodia, Malaysia, Philippines and Thailand, require that adequate or just compensation be paid for property expropriated. Others, such as Indonesia and Viet Nam, require that compensation be made in accordance with international legal principles or requirements. The AIMS report recommends that cross-border commercial agreements should prohibit or limit the government's right to expropriate, that events leading to expropriation should be made known in advance to investors, and that compensation should be paid in accordance with international legal standards and requirements if expropriation occurs.

- *Confidentiality of contracts:* Electricity producers may be reluctant to engage in power trade unless they have some reassurance that information on commercial operations and the terms of bilateral power contracts can be kept confidential. On the other hand, electricity producers and governments may want to have a clear understanding of what provisions will apply to contracts in the event of an emergency. For example, what will happen if a contract is terminated, what will happen when damage is caused by a fire or earthquake, and how will contractual disputes will be resolved? The AIMS report recommends that member economies draw up standard clauses on such emergency matters to be used in all cross-border power trades. This should allow the specific commercial aspects of each contract to be kept confidential, while reducing the time required for contract negotiations.

Yet another two regulatory issues in the AIMS report relate to **social policies**:

- *Immigration and employment:* It may be difficult for a power companies in two neighbouring economies to cooperate on cross-border interconnections unless they can each send some technical and management personnel abroad to work.

However, processes for obtaining visas and work permits and accrediting expatriate professionals are often complex. In this regard, the AIMS report suggests that member countries or utilities assist their partners on immigration and employment matters wherever possible in relation to ASEAN interconnections.

- *Consumer protection and safety standards:* Several ASEAN economies, including Brunei Darussalam, Malaysia, Indonesia, Philippines and Thailand, have consumer protection legislation. Brunei and Singapore have consumer protection associations through which complaints can be lodged. Brunei, Indonesia, the Philippines and Thailand have grid codes or technical standards that regulate the safety of electrical equipment and installations. Yet consumer protection and safety standards are certainly not uniform or universal. This creates the possibility that investments in cross-border transmission lines could be delayed by the failure of an entity in one economy to comply with standards in another. But differing safety standards should not be a problem if each entity participating in cross-border trade is responsible for facilities on its own side of the border. In any event, the AIMS report recommends that utilities develop common standards and codes of practice for consumer protection that can be incorporated into bilateral trade agreements.

Finally, four issues discussed in the AIMS report relate to market structure and competition:

- *Anti-competitive practices:* Independent power producers may be hesitant to build generating facilities whose output is destined for export if the importing economy has no laws in place to restrict unfair competition. Indonesia, Philippines and Thailand have specific laws on anti-competitive practices, while Malaysia and Singapore have explicit policies to promote power sector competition. But Malaysia and Thailand, while allowing competition among power generators, retain vertically integrated utilities which serve as single buyers for all power generated. Other ASEAN economies continue to grant a monopoly franchise for generation, transmission and distribution to vertically integrated monopolies. Since ASEAN economies are at different stages in opening their power markets to competition, the AIMS report simply states that implementation of competition law "will depend on each country's policy" on "whether to have an open market" and "whether to allow foreign competition" in its power industry.

- *Third-party access:* Independent power producers cannot effectively compete in export markets unless the importing economy allows them to have access to electric transmission lines. Among ASEAN economies, only the Philippines currently provides open and non-discriminatory access to transmission facilities. Since economies are at different stages of market reform, the report states that third-party access will depend on each country's policy regarding market opening.

- *Investment recovery:* In order for international transmission lines to be built, public or private investment must be drawn to their construction. If private investors are to be attracted, a market-based rate of return on capital is required. The AIMS report states that "incentives have to be put in place to encourage interconnection investment either by the government, existing utilities or private investors." It further states that "some mechanism has to be established…to apportion the cost of investment" in transmission lines between two economies.

- *Information access:* Economies vary in the degree to which national-level information is provided about the electricity industry. Market participants need information on electricity prices and demand in order to make reasoned decisions on when and where investment in generation and transmission facilities can earn a profit. Thailand and Viet Nam have public information about the electricity tariff structure, while Singapore and the Philippines have public information on current market prices. Malaysia has some information on the power sector in the public domain as well, though what sort of information is unclear from the report. There is also no mention in the report of public information on electricity demand, which suggests that such information may be substantially lacking. The report recommends that ASEAN economies agree on types of information to exchange and establish a framework to gather and exchange information on the internet.

HARMONISED RULES AND POWER TRADE IN NORTH AMERICA

Many of the issues confronting the ASEAN Power Grid have been dealt with already in the North American context. The most current point of reference here is the North American Free Trade Agreement (NAFTA) that was signed by Canada, Mexico and the United States in 1992 and entered into force in 1994. This built on many similar provisions in the US-Canada Free Trade Agreement that took effect in 1989. Relevant trade issues are also dealt with under the Columbia River Treaty of 1961, the Tax Convention of 1980 and the Air Quality Agreement of 1991.

First, it may be helpful to focus on issues that relate to the **ability** to trade power:

- ***Licensing:*** No specific license is required to trade electricity between the United States and Canada. Any entity licensed to operate in either economy may engage freely in power trade. However, a license is required from the governments of both United States and Canada for construction of international transmission lines.
- ***Supply to customers:*** Cross-border transactions involving supply of power by an entity in either Canada or the United States to a customer in the neighbouring economy are not restricted any more than domestic power transactions in either country. Since both economies provide for third-party access to high-voltage transmission grids, and since large industrial firms can link their facilities directly to such grids, an independent power producer in either economy may freely sell electricity to an industrial firm in the other. In those states and provinces that allow third-party access to local distribution grids, a generator in either economy may freely provide electricity to a commercial or residential customer in the other.
- ***Free flow of funds:*** NAFTA specifically provides for the free flow of funds between Canada, Mexico and the United States. Each of the economies "shall permit all transfers…relating to an investment…to be made freely and without delay." Such transfers include all revenues derived from an investment, including profits, dividends, interest, capital gains, royalty payments, management fees and other fees. They also include in-kind payments derived from an investment. Further, such transfers include "proceeds from the sale of all or any part of the investment or from the partial or complete liquidation of the investment." Finally, such transfers include payments under contract, including payments on loans.[92]
- ***Import and export restrictions:*** As already noted, there are no restrictions on the importation or exportation of power between the United States and Canada.

Next, it is helpful to focus on issues that relate to **taxation** of power trade. As noted earlier, double taxation or customs duties may make cost-reducing trade financially untenable.

- ***Corporate taxation and double taxation:*** The Canada-United States Convention with Respect to Taxes on Income and on Capital, originally signed in 1980 and since amended four times, has several provisions designed to avoid double taxation. Article VII, on business profits, provides that business entities will be taxed on profits in either economy only insofar as the profits are attributable to activity in that economy. Business profits in one economy "shall be taxable only" in that economy unless business is carried on in the other economy "through a permanent establishment situated therein." In that case, business profits" in the other economy "may be taxed…but only so much of them as are attributable to that permanent

[92] NAFTA, Article 1109.

establishment." If a business headquartered in one economy carries on business in the other through a permanent establishment, "there shall in each [economy] be attributed to that permanent establishment the business profits which it might be expected to make if it were a distinct and separate person…."[93]

- *Customs duties:* No customs duties are levied between Canada and the United States on any goods or services. The US-Canada Free Trade Agreement eliminated all customs duties on goods by the end of 1997. No duties had been levied on electricity trade between the two economies for many years before then. NAFTA provides for the elimination of most Canadian and US tariffs with Mexico by 2004.

Proceeding to regulatory issues that relate to the **rule of law**:

- *Expropriation of assets:* NAFTA expressly states that "no party shall directly or indirectly nationalize or expropriate an investment" except for a public purpose, on a non-discriminatory basis, in accordance with due process of law, and upon payment of compensation. The "compensation shall be equivalent to the fair market value of the expropriated investment." In addition, "compensation shall be paid without delay and be fully realizable" and "shall include interest at a commercially reasonable rate" for the period between expropriation and payment.[94]

- *Confidentiality of contracts:* Commercial terms of power contracts between entities in the United States and entities in Canada or Mexico can be kept confidential. NAFTA provides that "each Party shall maintain the confidentiality of confidential business information" collected for customs purposes "and shall protect that information from disclosure that could prejudice the competitive position of the persons providing the information."[95] However, there are regulatory requirements to provide substantial amounts of information on the power trade that takes place. In the United States, FERC collects data on the number of megawatt-hours each company generates, purchases, receives, delivers, transmits for others, sells in wholesale markets for resale to others, and sells to final customers. FERC also collects information on the length, voltage and cost of each transmission line in service and each line added during the year.[96]

- *Dispute Resolution:* This issue was mentioned only briefly in the ASEAN context above, but constitutes a core feature of trade provisions in NAFTA. Subchapter B of NAFTA, on Settlement of Disputes between a Party and an Investor of Another Party, "establishes a mechanism for the settlement of investment disputes that assures both equal treatment among investors of the Parties in accordance with the principle of international reciprocity and due process before an impartial tribunal." Investors who allege they have incurred loss or damage due to a breach of the agreement's provisions may submit their claim to arbitration within three years of the time they discovered or should have discovered the breach and the resulting loss or damage. Detailed provisions are specified for doing so, as well as for appointing impartial arbitrators. Awards for arbitrated claims may include monetary damages and applicable interest, as well as restitution of property, but not punitive damages. However, parties are enjoined to try to settle disputes through consultation or negotiation if possible.[97]

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93 Government of Canada and Government of the United States of America (1980), Article VII, paragraphs 1 and 2.

94 NAFTA, Article 1110.

95 NAFTA, Article 507.

96 FERC Form 1, pages 400-402, 422-25.

97 NAFTA, Articles 1115-1135.

Further regulatory issues relate to **social and environmental policies**:

- ***Immigration and employment:*** As noted above, the construction of cross-border transmission lines can be facilitated if there is flexibility to select management and technical personnel from both economies involved. NAFTA states that no participating economy can require an enterprise in that economy which is controlled by investors in another economy to "appoint to senior management positions individuals of any particular nationality." It also simplifies cross-border employee transfers, requiring each participating economy to "grant temporary entry…to a business person employed by an enterprise" in another participating economy "in a capacity that is managerial, executive or involves specialized knowledge" if the person has been "employed continuously by the enterprise for one year" of the last three. Finally, NAFTA enables engineers and other professionals who are citizens of one participating economy to work for a firm that is based in one of the other participating economies, provided they have a specific job offer for a period not exceeding one year.[98]
- ***Environmental, health and safety standards:*** NAFTA allows participating economies to set strong environmental, health and safety standards but does not allow parties to weaken such standards in an attempt to attract business. "The Parties recognize that it is inappropriate to encourage investment by relaxing domestic health, safety or environmental measures. Accordingly, a Party should not waive or otherwise derogate from, or offer to waive or otherwise derogate from, such measures as an encouragement for the establishment, acquisition, expansion, or retention in its territory of an investment…." But "nothing…shall be construed to prevent a party from adopting, maintaining, or enforcing any measure…to ensure that investment activity in its territory is undertaken in a manner sensitive to environmental concerns."[99] Canada and the United States are also bound by the Air Quality Agreement of 1991 to reduce power plant emissions of sulphur dioxide and nitrogen oxide in order to control acid rain and smog.[100]

Finally, several issues relate to market structure and **competition**:

- ***Anti-competitive practices:*** Both Canada and the United States vigorously pursue anti-competitive behaviour under their respective antitrust laws. The US Federal Regulatory Commission also frequently conditions its required approval of mergers of power industry firms on remedies to make the firms more competitive.
- ***Third-party access:*** Both the United States and Canada have had regulatory regimes in place since the mid-1980s which ensure that competing independent power producers have non-discriminatory third-party access to the power grid. Competitive behaviour is ensured primarily not by antitrust laws, which address misbehaviour after the fact, but by the structural unbundling that FERC requires between generation, transmission, distribution and supply functions. This makes it difficult for firms that own both transmission and generating facilities to discriminate against generation by other firms in granting access to transmission. FERC is further in the process of requiring operational unbundling, whereby the transmission facilities in each area are controlled by an Independent System Operator. When operational unbundling is fully implemented, discrimination by transmission owners in favour of their own generation will be virtually impossible.[101]

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98 NAFTA, Article 1107, Article 1603 and Annex 1603.

99 NAFTA, Article 1114.

100 Government of Canada and Government of the United States of America (1991), Article IV and Annex I. Government of Canada and Government of the United States of America (2000), (2002).

101 APEC Energy Working Group (2003), pages 22 and 146. IEA (2002), pages 68-71.

- *Investment recovery:* In general, rates of return on international transmission lines between the United States and Canada are based on market cost of capital. However, investment in new transmission has been declining steadily in the United States for a quarter century, as noted in an earlier chapter. So it could be argued that if rates of return were more attractive, more international lines would be built.
- *Information access:* Both Canada and the United States require substantial amounts of detailed information on power transactions to be made public. Prices and quantities of electricity traded, amounts of power generated and transmitted, and corporate balance sheets and financial statements are all in the public domain. Market participants can thus make informed decisions about where to invest.

CONCLUDING OBSERVATIONS

Strong parallels exist between the means that have been adopted to boost power trade in North America and the harmonising methods that have been proposed to boost power trade in Southeast Asia. In both cases, the ability to trade power is facilitated by cross-border licensing of entities involved in power trade, the ability of generators in one economy to supply power to customers in neighbouring economies, the free flow of funds between economies, and the elimination of restrictions on power imports and exports. Power trade is also assisted in both cases by agreements to avoid double taxation of revenues from power trade and customs duties on power trade. Another key ingredient of robust power trade is legal protection for the confidentiality of contracts and against the expropriation of assets. Construction of cross-border transmission lines can also be expedited if the parties involved are free to choose the best-qualified management and technical personnel from among all the economies involved. Finally, cost-saving power trade can be boosted through regulations to ensure non-discriminatory access to the grid by competing power producers.

POWER INDUSTRY REFORM AND ITS IMPACT ON POWER GRIDS

INTRODUCTION

Most APEC economies are reforming their electric power markets in one way or another to make them more competitive. However, they are doing so at different speeds and to different extents. Some still have vertically integrated utilities with a monopoly over generation, transmission, distribution and supply of power. Many of these are considering measures to introduce competition among generators. Other economies have opened up their markets to wholesale competition in which independent power producers sell power over the grid to a single buyer, often a utility that continues to combine transmission, distribution and supply functions. Still other economies have opened up part of their markets to retail competition in which final consumers have a choice of electricity suppliers, and various suppliers compete for their business.

The fact that different economies are at different stages of reform may present an obstacle to building transmission grids between them. Independent power producers in rapidly reforming economies may be reluctant to accept competition from vertically integrated monopolies in more slowly reforming economies since such monopolies may be able to cross-subsidise their generation with revenues from transmission and distribution. Conversely, vertically integrated monopolies that have traditionally enjoyed protected markets in their home economies may be reluctant to accept competition from independent power producers in rapidly reforming economies abroad.

In practice, however, it is also possible that varying degrees of reform in different economies do not present an insurmountable barrier to transmission links between them. Independent power producers in the rapidly reforming economies may be confident of their commercial prowess and quite willing to take on competition from vertical monopolies whose costs may be higher since they have not been forced to adopt efficiencies by competition at home. Meanwhile, the vertical monopolies may be eager to embrace large new potential markets outside their home territory, especially if they can build new generating capacity faster than their own economy requires it.

In any event, the potential impact of disparities in power industry regulatory regimes would appear to be much more considerable for Northeast Asia and Southeast Asia than for Japan or North America. In the case of Japan, which has limited wholesale competition but substantial retail competition, all power producers face the same set of economic regulations. In the case of North America, both Canada and the United States have fully liberalised their wholesale markets, and independent power producers constitute a large and growing share of electricity generation. In Northeast and Southeast Asia, however, power markets in various economies are clearly reforming at much different speeds, so disparities in economic regulation of power markets may be an issue.

It is also interesting to consider whether barriers to power grid expansion may be raised by linkages between gas and power markets. Certain gas-exporting economies in APEC, including Indonesia, Malaysia and Brunei Darussalam, have traditionally offered gas to their domestic power producers at subsidised prices which are well below the price of gas on export markets. Were they to continue doing so as power trade grows across economies, they could be seen to explicitly subsidise power not only in domestic markets but also internationally, which might raise strong objections by independent power producers in importing economies. Moreover, insofar as exports of power generated from gas were seen to be displacing exports of gas by pipeline for production of power abroad, domestic gas producers might object to further expansion of power grid interconnections because such expansion would reduce their potential revenues on gas sales. So stronger power grid links with gas-exporting economies may require measures to ensure that gas used in power generated for export is no longer sold to power utilities below the market price.

POWER INDUSTRY REGULATION IN NORTH AMERICA

The United States and Canada have extensive competition throughout their wholesale power markets and in major portions of their retail power markets as well. There has been rapid growth in the role of independent power producers (IPPs). In Canada, where traditional utilities have the advantage of substantial low-cost hydropower resources, IPPs serve less than 2 percent of load.[102] In the United States, however, IPPs provided roughly a quarter of all electricity generated in 2002, and IPPs have built and financed almost all new electric generating capacity completed in recent years.[103]

Under the federal system of government in each economy, regulatory authority over the transmission system of high-voltage power lines is held by the federal government while regulatory authority over local power distribution grids is held by states, provinces or territories. In each economy, the federal government has provided for open and non-discriminatory access to the high-voltage transmission network. As a result, large industrial firms, which can link directly to high-voltage power lines, have a clear choice among competing electricity generators.

But while some states, provinces and territories have provided for open access to local power distribution grids, others have not. Thus, residential and commercial customers, who can buy electricity only from these local grids, cannot all choose their electricity supplier. In the United States, 17 of the 50 states with nearly half the economy's population have given such customers a choice of retail power suppliers. In Canada, small customers have been granted a choice of power suppliers in the most populous province, Ontario, as well as in Alberta, which together account for half the population.[104]

In North America, there is little integration between natural gas and power markets. Gas fuels a growing share of electricity generation, reaching 8 percent in Canada and 16 percent in the United States in 2000.[105] But each of the many competing electricity generators has a choice among many competing gas suppliers. Gas markets in the two economies are closely tied by an extensive network of gas pipelines through which open access by all suppliers is assured by the regulatory regime in each economy. There are hundreds of gas producers competing for generators' business.

Few companies engaged in the production or transmission of gas are also engaged in the generation of electricity. Thus, there is generally no incentive for a gas company to provide gas on a preferential basis to any electricity generator, and it will sell to the generator willing to pay the most. Conversely, there is generally no reason why any electricity generator would wish to obtain gas from any but the least-cost source of supply. Moreover, under FERC Order 636, gas production, transportation and retail supply must be conducted by functionally separate businesses, with information firewalls between them. So even if a gas producer or transporter wished to direct cheap gas toward an affiliated electricity generator, it would find it difficult to do so.[106]

POWER INDUSTRY REGULATION IN NORTHEAST ASIA

Among the economies of Northeast Asia, the pace and ultimate extent of power industry reform differ quite a lot. In North Korea and Mongolia (not APEC members), the generation, transmission, distribution, and supply of power are controlled by the state or state-owned corporations. In Russia, a state-owned firm continues to dominate the industry, although some reform measures have been proposed. In China, there are several large power companies that nominally compete with each other, but actual competition among them is so far quite limited, and

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102 Natural Resources Canada (2000). At the end of 1997, non-utility generators, including industrial establishments, small utilities and IPPs, had 7.3 percent of total installed generating capacity in Canada. Of this amount, small utilities and IPPs held about 18 percent. Thus, IPPs accounted for no more than 1.3 percent of total generating capacity.

103 APEC Energy Working Group (2003), page 146.

104 Ibid., pages 22-23, 146. North America Energy Working Group (2002), chapter 5.

105 APEC Energy Working Group (2002b), pages 42-43, 272-73.

106 APERC (2003), pages 19, 58, 147.

independent power producers are very few in number, although large industrial firms are allowed to choose their retail supplier. In Japan, the wholesale market is nominally open to competition from all players, and a growing share of retail customers have a choice of suppliers, but slow market growth and difficulties in importing gas have limited IPPs to less than one percent of total electricity generation. In South Korea, all customers could have a choice of retail suppliers within a few years, and one out of seven kilowatt-hours of electricity generated is sold by competing IPPs.

MONGOLIA

Generation, transmission and distribution of power in Mongolia were unbundled from each other and placed in separate government-owned corporations pursuant to the Energy Law and Government Resolution 164 that were promulgated in 2001. The government intends gradually to privatise new or existing energy assets, as well as to commercialise energy enterprises so that profit becomes a key management goal. It thereby hopes to enable eventual market competition.[107]

NORTH KOREA

Power plants, transmission lines and distribution grids in North Korea are owned by the state. The transmission and distribution system, which reportedly dispatches power from 42 hydroelectric plants and 20 thermal plants, is supposed to be controlled by the Electric Power Production and Dispatching and Control Centre in Pyongyang. However, while many government agencies are involved in the power sector, none is fully responsible for power system operations, planning, or management.[108] There are no plans to introduce competition into North Korea's power industry.

RUSSIA

Russia's power industry is dominated by the state-owned United Energy System of Russia, which generates four fifths of all the economy's electricity and retains a near monopoly on power transmission, distribution and retailing as well. Its only major competition on the generating side comes from the state-owned nuclear power company, Minatom, from municipal utilities, and from industrial firms that generate power for their own use. Municipal utilities distribute power as well.

Russia's power market is vertically integrated to a great extent with its gas market. Half of the economy's electricity is generated from gas, most of which must be purchased from Gazprom, which produces about seven-eighths of all gas in the economy even though it is no longer a legal monopoly. So inefficiencies in gas production are readily passed on to power producers, who have limited flexibility to shift to other fuels, and power producers can pass on increased gas prices in their rates to electricity consumers, who usually have no alternative source of power.[109]

But competitors' share of gas production is growing under a system of negotiated third-party access. Since 2001, independent suppliers have been allowed to negotiate for use of any pipeline network capacity not being used by Gazprom, which is supposed fulfil bids for spare capacity on a non-discriminatory basis in proportion to suppliers' transportation volumes. Transmission tariffs, however, may be two to three times Gazprom's internal transmission costs. The government called in 2000 for the organisation of independent gas transmission companies whose transmission charges might be more even-handed.[110] If Russia's gas market becomes more competitive over time, competition in its power market might also be enhanced.

CHINA

China has recently established a significant degree of wholesale competition in its power market, as well as retail competition for large industrial customers. According to the Tenth Five Year Plan, wholesale competition is to be fully implemented by 2005, with all power producers

[107] Mongolia Ministry of Infrastructure (2004).

[108] Von Hippel and Hayes (1998), pages 85, 90-92.

[109] APERC (2003), pages 126-27.

[110] International Energy Agency (2002), *Russia Energy Survey 2002*, pages 121-24.

selling electricity to power grids on a competitive basis. Under the power industry reform programme approved in 2002, the generating and transmission assets of the State Power Corporation of China (SP) were unbundled. SP's transmission assets, which had covered most of China's provinces, were placed in a new State Grid Corporation of China (SGCC) which includes regional grids for eastern, central, northern and northwestern China and supervises a separate grid in remote Tibet. A new China Southern Power Grid Corporation has been given control of a southern grid including transmission assets in the provinces of Guangdong, Hainan, Yunnan, Guizhou and Guangxi.

SP's generating assets, which had comprised nearly half of China's total generating capacity, were about evenly divided between five separate companies, called Datang, Huadian, Huaneng, Longyuan and Power Investment. China's remaining generating assets are divided between the state hydropower and nuclear power authorities, 45 municipal power companies, rural power authorities, and a limited number of independent power producers (IPPs). Most of the generating entities have access to one of the five regional power grids, enabling them to compete in the wholesale market for the business of local distribution companies (which provide electricity to most final customers) and in the retail market for the business of large industrial firms.[111]

China's power market has only very weak links to its gas market since little power is produced from gas. Gas fuels only about 2 percent of electric generating capacity in China and is unlikely to fuel more than 6 percent in 2020.[112] Still, wholesale competition in the power market would be somewhat enhanced if generators could compete on gas costs. Indeed, wholesale competition could develop in the gas market as a growing share of gas demand is met by imports. These might come as LNG from Indonesia, Malaysia, Brunei or Australia or by pipeline from Kazakhstan, Turkmenistan, or Russia. Today, however, the China National Offshore Oil Corporation (CNOOC) controls all LNG terminals, while the China National Petroleum Corporation (CNPC) and Sinopec retain parallel northern and southern monopolies on pipelines. If this troika of gas transport monopolies is not reformed, power producers will still have to obtain gas from a single gas buyer in each area and will thus remain unable to compete on gas price.[113]

JAPAN

Japan is gradually introducing competition into its power market. At present, the market is dominated by an integrated utility in each of ten different service areas. The ten integrated utilities generate most of their own power but also buy large amounts from the Electric Power Development Company (EPDC), which runs most of the economy's hydropower plants and many of its coal-fired plants as well. The government holds 83 percent of EPDC's shares with the intent of privatising them, while 17 percent are held by nine of the utilities. Wholesale competition for sale to the integrated utilities is still quite limited, as independent power producers (IPPs) accounted for less than 1 percent of generation and generating capacity in 2003. However, amendments to the Electric Industry Law have allowed larger customers to shop around for the least-cost electricity supplier. In 1999, retail choice was opened to large industrial customers with 2 MW of demand or more, which accounted for some 26 percent of demand in 2003. In 2003, retail choice was expanded to cover 40 percent of demand (customers contracting for more than 500 kW) by April 2004 and 63 percent of demand (customers contracting for more than 50 kW) by April 2005.[114]

Japan's power market is vertically integrated to a significant degree with its gas market. Gas accounted for 26 percent of generating capacity and 26 percent of electricity generated in 2000.[115] Electric utilities import gas through their own LNG terminals, and have not been obliged to provide access to these terminals to competitors, who have not managed to build their own

[111] APEC Energy Working Group (2003), page 39. IEA (2002), pages 140-141.

[112] IEA (2002), pages 124, 126.

[113] Fridley (2002), pages 48-52. Stern (2002), pages 251, 272.

[114] The Institute of Energy Economics, Japan (2002). Government of Japan and Government of the United States (2003). Electric Power Development Company (2003a), pages 35-6, and (2003b).

[115] APEC Energy Working Group (2002a), page 119. Of 229,150 MW of generating capacity, 60,280 MW was gas-fired.

terminals on the scale required and who have not been able to obtain gas from regional gas utilities on competitive terms. Since the electric utility in each region supplies gas to itself, it can pass on inefficiencies in procurement, shipping and processing, as well as in the construction and operation of LNG facilities, in higher prices to electricity consumers, who have few alternative power sources. However, an amended Gas Utility Law passed in 2003 will require that the owners of LNG facilities make public the amount of capacity at such facilities that is not being utilised, negotiate for use of such capacity by third parties, and explain why access to spare capacity is denied, if that is the case. This may expand opportunities for competing power producers to enter the marketplace.

SOUTH KOREA

In South Korea, there is growing competition from independent power producers (IPPs), which accounted for 14 percent of generating capacity in 2000. Pursuant to electricity industry restructuring plans that have passed the National Assembly, open access would be provided to the electric transmission network after 2004 and to electric distribution grids after 2009. There would then be wholesale competition among electricity generators for sales to power distribution companies, followed by retail competition among generators for sales to final customers. However, there are recent indications that these market-opening plans may not proceed as scheduled.

South Korea's power market is vertically integrated with its gas market to a significant degree. Natural gas accounted for 10 percent of electricity generation and 26 percent of electric generating capacity in Korea in 2002, with nearly a quarter of the gas-fired capacity owned by IPPs.[116] Gas is provided to all power producers through a single supplier, the Korea Gas Corporation (KOGAS). Until 2006, the Korea Electric Power Company (KEPCO) is obliged to purchase a certain amount of gas under take-or-pay arrangements with KOGAS, perhaps restricting the available supply of gas to other power producers.[117] Large gas consumers are allowed to import LNG for their own use instead of buying it from KOGAS, but none had found it practical to do so as of the end of 2002.

As long as all power producers obtain gas from the same source, the effective scope for competition among their gas-fired power plants will be limited to capital and operating costs. Given the large share of gas-fired generating capacity, their flexibility to shift to other fuels in response to higher prices will also be limited. Thus, KOGAS has considerable market power to pass on inefficiencies that may occur in gas procurement, shipping, and processing, as well as in construction and operation of LNG facilities and pipelines, in higher gas prices to power producers. But proposals have been made within the government for KOGAS to provide open access to all LNG, pipeline and storage facilities. If such proposals were implemented, this might help extend competition in the power sector by making it easier for IPPs to obtain gas on competitive terms.[118]

POWER INDUSTRY REGULATION IN SOUTHEAST ASIA

Among the economies of Southeast Asia, the status of power industry reform spans a broad range. In Cambodia, Laos, and Myanmar, as well as Brunei Darussalam, there are vertically integrated power monopolies and no plans to alter them. In Malaysia, Indonesia and Viet Nam, there has been some unbundling of generation and transmission assets, with plans to introduce wholesale and retail competition over the next several years. In the Philippines, Thailand and Singapore, wholesale and retail competition in power markets are already in place or imminent. Boosting power trade among such disparate power industries could prove to be problematic.

CAMBODIA

A state-owned limited liability company, Electricité du Cambodge (EDC), owns and operates all power plants, transmission lines and distribution grids in Cambodia. The economy's power

116 Yoon, Kim and Park (2003). IEA (2002e), pages 55 and 57. IPPs had 6,708 MW of generating capacity in 2000, or 14 percent of Korea's 48,451 MW. IPPs had 2,872 MW was gas-fired capacity, or 23 percent of Korea's 12,698 MW.

117 IEA (2002c), page 55.

118 APERC (2003), pages 94-97.

market is very small, and EDC had only 115 MW of installed capacity as of April 2002. Moreover, the market is fragmented into 24 local grids, with three-quarters of demand in the capital, Phnom Penh.[119] Hence, the power system is too small to achieve the economies of scale available in most other power markets, and Cambodia's electricity tariffs are among the highest in the region, ranging from US$0.15 per kWh in Phnom Penh to $0.30 to $0.92 in the provinces. Competition among independent power producers might further fragment the market, making scale economies even harder to achieve, which is probably why there are no proposals to introduce such competition.[120]

However, the government encourages private sector participation in the power industry through competitive bidding for power purchase agreements with EDC.[121] It also supports grid connections with neighbouring economies, such as a 220 kV line pursuant to the Greater Mekong Subregion Power Transmission Project. This line should allow substantially cheaper electricity to be imported into the Phnom Penh area.[122] That consideration apparently outweighs any possible misgivings about exposing the economy's underdeveloped power industry to external competition.

LAOS

A state-owned corporation, Electricité du Laos (EDL), owns and operates all transmission lines and distribution grids in the Lao People's Democratic Republic. It also owns and operates 42 percent of the hydropower that makes up 97 percent of the economy's electric generating capacity. Two independent power producers (IPPs) account for most of the remaining hydropower capacity (57 percent), but EDL owns 60 percent of one (Theun-Hinboun) and 20 percent of the other (Houay Ho).[123] The IPP capacity is basically used to generate electricity for export to Thailand, while EDL's fully-owned capacity is used to generate electricity for the domestic market.[124]

The government expects to develop some 7,000 MW of additional hydropower capacity by 2020, largely for export to Thailand and Vietnam through build-own-operate-transfer (BOOT) projects.[125] Lack of competition in the domestic market is therefore apparently not an obstacle to power trade with neighbouring economies whose power markets are more competitive. This can be attributed to an understanding on the part of the government that the economy's hydropower resources should be a major revenue source provided that they can be developed and exported.

MYANMAR

A state firm, Myanma Electric Power Enterprise (MEPE), owns and operates all power plants, transmission lines and distribution grids in the economy. It is the sole supplier of electricity to industrial, commercial and residential customers. MEPE is regulated by the Ministry of Electric Power. There are no public proposals to introduce competition into Myanmar's power industry.[126]

BRUNEI DARUSSALAM

In Brunei Darussalam, all power is produced and transported by one of two government entities, each of which operates as a vertically integrated monopoly in its service territory. Depending upon the area, the entity is either the Department of Electrical Services (DES) in the Ministry of Development or the Berakas Power Company (BPC), which is government-owned.

Brunei's power market is also vertically integrated with its gas market. Over 99 percent of the economy's electric generating capacity is gas-fired. DES and BPC are obliged to buy all their gas from Brunei Shell Petroleum, which is half-owned by the government and controls 90 percent of

119 Tun (2002).

120 Asian Development Bank (2003).

121 ASEAN (2004).

122 Asian Development Bank (2003).

123 Prathoumvan and Visounnarath (2002).

124 ASEAN Interconnection Master Plan Study Working Group (2003), volume II, page 4-3.

125 Pramathoumvan and Visounnarath (2002).

126 ASEAN Centre for Energy (2004).

the economy's gas production and transportation. Brunei Shell Petroleum, for its part, sells gas in the domestic market only to DES and BPC. It holds gas prices to the power utilities substantially below gas prices on export markets, presumably according to the wishes of the government, but it is not clear whether the utilities pass on all the cost savings in reduced rates to electricity users.[127]

VIET NAM

Viet Nam's power market is dominated by Electricity of Viet Nam (EVN), an integrated utility that controlled thirteen power plants, four transmission companies, and seven distribution companies as of 1998. However, there is some nascent wholesale competition, with independent power producers selling power to EVN in the role of single buyer. One IPP began generating power in 1998, and a joint venture involving Japanese and French power companies is building a large gas-fired combined cycle plant under a build-operate-transfer contract.[128]

The effectiveness of evolving wholesale power market competition in Viet Nam may be quite limited unless competition is also allowed in the gas market which is vertically integrated with it to a substantial degree. For the 18 percent of the economy's electricity that was generated from gas in 2001, there was only a single gas supplier, the state-owned Viet Nam Oil and Gas Corporation (PetroVietnam), an integrated firm responsible for exploration, production and transportation. All gas-fired plants obtain gas from PetroVietnam under long-term take-or-pay contracts. If this continues to be the case, then insofar as gas continues to be the fuel of choice for meeting growing power demand, IPPs will be able to compete only on capital and non-fuel operating costs.[129]

INDONESIA

Indonesia's power sector is dominated by the integrated state public utility, Perusahaan Listrik Negara (PLN). Independent power producers (IPPs) have been allowed since 1993 and own about 9 percent of the economy's electrical generating capacity. This has brought wholesale competition to the power sector, which should be further encouraged by an electricity law that was promulgated in 2002. But all the output of IPPs must be sold through PLN, which retains a monopoly on electricity transmission, distribution and retailing. Hence, there is no guarantee that cost savings to PLN that result from wholesale price competition will be passed fully to power consumers.

Indonesia's power market is vertically integrated with its gas market to a great extent. Roughly three-eighths of the economy's electric generating capacity was gas-fired in 1999. PLN and IPPs must purchase gas from the same producer, Pertamina, which has a legal monopoly on gas production. So generating costs for their gas-fired power plants will be changed by similar amounts if Pertamina raises or lowers its prices. And since a large share of generating capacity is gas fired, power producers have limited flexibility to shift to other fuels. It follows that at least when gas generates power at the margin, as it normally does when demand is heavy, the scope for wholesale competition is limited to capital and non-fuel operating costs.

However, the 2001 Oil and Gas Law should gradually move the gas market toward wholesale competition. The law specifies that exploration and exploitation, as well as processing, transportation, storage and trading, should be conducted in a competitive fashion. Thus, as of late 2003, Pertamina no longer has a monopoly on oil and gas development and no longer has to be included in production sharing contracts. With new production contracts awarded on a competitive basis, wholesale competition should evolve in the gas market as gas production expands over time. Consequently, competing power producers will eventually be able to shop around for the least costly gas, and the effective scope for wholesale competition in the domestic power market should expand.[130]

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[127] APEC (2003), pages 51-52.

[128] APEC Energy Working Group (2002a), page 128.

[129] APEC (2003), pages 152-53.

[130] Ibid., pages 80-82.

MALAYSIA

Malaysia would appear to have a highly competitive wholesale power market, with 43 percent of its electricity generated by independent power producers (IPPs). But the state-owned electric utility, Tenaga Nasional Berhad (TNB), retains a monopoly on transmission, distribution and retailing in Peninsular Malaysia. Thus, it is not clear to what extent TNB's cost savings through competitive wholesale market purchases are passed along to final retail power consumers.

Furthermore, Malaysia's power market is vertically integrated with its gas market to a very great extent. More than three-quarters of the economy's electricity generation in 1999 came from gas, and more than four-fifths of its gas consumption goes to the production of electricity. Of incremental capacity planned through 2005, more than half is gas-fired. TNB and IPPs buy gas from the same producer, Petronas, which has a legal monopoly on gas production and transmission. So their cost for generating power from gas-fired power plants will be changed by similar amounts if Petronas raises or lowers its prices. Moreover, with the overwhelming share of gas-fired generating capacity, power producers have extremely limited flexibility to shift to other fuels. So when gas generates electricity at the margin, which it does most of the time, the scope for competition in Malaysia's wholesale market is limited to capital and non-fuel operating costs.[131]

THAILAND

Thailand's power sector is moving toward full competition. The wholesale power market is already quite competitive, with independent power producers (IPPs) and small power producers (SPPs) owning 36 percent of all generating capacity as of the end of 2002. Three state-owned enterprises, namely the Electricity Generating Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA), which together control most of the remaining capacity, should be privatised by 2004. Retail supply is to be deregulated in 2004 as well, allowing all customers to choose among the many competing electricity suppliers.[132]

Yet competition in Thailand's power market is hampered to a significant degree by elements of vertical integration with its gas market. About two-thirds of the economy's electricity is generated from gas, which accounted in 1999 for 42 percent of generating capacity. All power industry competitors must buy gas from the Petroleum Authority of Thailand (PTT), which produces roughly two-fifths of the economy's gas and serves as the single buyer in a competitive wholesale gas market for the rest. So their gas prices are similar and the scope for competition among their gas-fired plants is limited to capital and non-fuel operating costs. With the very high share of gas-fired generating capacity, power producers have little flexibility to shift to other fuels. As a result, PTT has substantial market power to pass on costs of inefficiencies that may arise in gas procurement, shipping, processing and transportation by charging power producers higher gas prices.

Looking forward, the government foresees an expansion of business-to-business competition in the gas market. In this vision, independent power producers, industrial firms, small commercial businesses and transportation providers would be able to choose among competing gas suppliers. If such a vision could be realised, in view of the substantial competition that exists in the power market, lower prices from gas market competition would likely be passed on to electricity users.[133]

PHILIPPINES

There is clear movement toward a competitive power supply system in the Philippines. The Electric Power Industry Reform Act of 2001 provides for the unbundling of power sector assets into generation, transmission, distribution and supply. A competitive wholesale power market is to be established by selling off the generating assets of the National Power Corporation (NPC) in several pieces, by setting up an independent operator for NPC's transmission grid, and by creating a

131 Ibid., pages 100-101.

132 APEC Energy Working Group (2002a), page 114.

133 APEC (2003), page 140.

wholesale electricity spot market to facilitate trade. Open access to transmission and distribution grids should later allow consumers to choose among competing retail suppliers.[134]

But the development of competition in the Philippines power market may largely depend on the growth of competition in the gas market with which it is vertically integrated to a significant extent. For the 16 percent of the economy's electricity that was generated from gas in 2002, there was only a single gas supplier. But if domestic gas production expands and LNG facilities are built as anticipated to open up imports, multiple suppliers of gas should evolve. A government circular issued in 2002 would require that access to spare capacity at gas pipelines and LNG facilities be made available to all competing gas suppliers on a non-discriminatory basis. With alternative gas sources available from which to choose, new gas-fired generators may be built and may actively compete with each other on fuel prices as well as capital and operating costs.[135]

SINGAPORE

Singapore's electric power market is open to wholesale competition and partially open to retail competition. Four different companies compete to generate power, and large retail customers are allowed to choose among these and any other suppliers. The electric transmission and distribution grids are owned by PowerGrid Ltd, which owns no generating capacity and can therefore be expected to transport power from all competing generators on a non-discriminatory basis.[136]

However, actual competition in Singapore's power market has so far been quite limited since a large share of generating capacity is held by a dominant supplier, Power Senoko. Moreover, there is a significant degree of integration between the economy's power and gas markets. A fifth of the economy's power was generated from gas in 1998, and the share grew in 2001 with the opening of gas pipelines from Indonesia.[137] Power Senoko obtains its own gas through a contract with Malaysia. Tuas Power, another large supplier, buys its own gas through a contract with Indonesia.[138]

ISSUES ARISING FROM LINKS BETWEEN GAS AND POWER MARKETS

Brunei Darussalam, Indonesia and Malaysia are mature gas exporters with vertically integrated monopolies in their internal gas markets. Each of these economies is a major source of gas supplies for other APEC economies, and they dominate gas supply in Japan and Korea. In each case, moreover, the price that the integrated gas monopoly charges to power domestic producers has been held well below the price of gas on export markets. Insofar as gas and power grids develop within Southeast Asia, this situation, if continued, could well raise significant competition issues. This section briefly assesses the implications of the gas subsidies to power markets under three different scenarios: continued subsidies without restriction, continued subsidies with a tariff or regulation to limit their leakage into regional power trade, and elimination of subsidies.

THE CASE OF CONTINUED GAS SUBSIDIES TO DOMESTIC POWER INDUSTRY

Suppose that power producers in exporting economies are allowed to buy as much gas as they want at the subsidised domestic price, while exporting as much power as they like at market prices. The implications for the exporting economies would be as follows:

- Power producers make substantial profit on gas-fired power. They will be able to undercut competitors abroad since their gas inputs cost them less.

[134] APEC Energy Working Group (2002a), pages 92-3.

[135] APEC (2003), pages 121-22.

[136] Ibid., page 132.

[137] APEC Energy Working Group (2002a), page 104 and (2002b), pages 230-31.

[138] APEC (2003), page 131.

- Gas producers make less money since they are selling more gas to the power producers at the subsidised domestic price to meet power export demand, so less gas is available to sell at the higher (unsubsidised) export price.
- Governments may be more or less well off depending on their relative shares of ownership in dominant gas and power producers.
- The social objective of a price subsidy for electricity consumers is retained.

The implications for international trade and importing economies would be as follows:

- The domestic price subsidy for gas sold to power producers is extended to an external price subsidy for power exported to neighbouring economies.
- Consumers in neighbouring economies may benefit from somewhat lower power prices since power producers are able to offer power for export on the basis of subsidised fuel costs. But the same consumers may pay somewhat higher gas prices since gas producers are selling less gas directly to the international market.
- Power producers in neighbouring economies may complain of unfair competition since power producers in the exporting economies pay less for gas fuel inputs than they do, even before transportation cost differentials are taken into account.

THE CASE OF DOMESTIC GAS SUBSIDIES WITH COMPENSATING TARIFF

Suppose that power producers in exporting economies are still allowed to buy as much gas as they want at the subsidised domestic price, while exporting power at market prices, but a tariff is placed on exported power, equivalent to the differential between subsidised and market prices for gas inputs. The implications for the exporting economies would be as follows:

- Power producers make no extra margin on export sales since they are now indifferent between selling power domestically and internationally. But they may sell more power in the short term if there is surplus power to be exported when domestic load is below peak. They may also sell more power in the long term if transmission links make extra generating capacity profitable to build.
- Gas producers make less money since they are selling more gas to the power producers at the subsidised domestic price to meet power export demand, so less gas is available to sell at the higher (unsubsidised) export price.
- Governments raise money through the tariff, roughly equivalent to the amount that the gas producers are foregoing. Total gas revenues to the economy (the sum of gas revenues to gas producers and government) are the same regardless of whether gas is exported directly by pipeline or indirectly over electric transmission lines.
- The social objective of a price subsidy for electricity consumers is retained.

The implications for international trade and importing economies would be as follows:

- A price subsidy on power exported to neighbouring economies is avoided.
- Consumers in neighbouring economies no longer see reduced power prices resulting from gas price subsidies, but they may still benefit from lower prices insofar as trading reduces overall average regional costs for delivered electricity.
- Power producers in neighbouring economies cannot complain of unfair competition since power producers in the exporting economies pay the same for gas fuel inputs as they do, except for differentials in transportation costs.

THE CASE OF DOMESTIC GAS SUBSIDIES ELIMINATED

Suppose, as another alternative, that gas price subsidies for power producers are discontinued. The implications for the exporting economies would be as follows:

- Power producers buy gas at the market price, so at a given price for power, their margin on sales will be the same in domestic and export markets.
- Gas producers no longer sacrifice revenues since they are no longer subsidising gas for domestic power customers; their revenues are the same regardless of whether gas is exported directly or sold to power companies.
- Governments may be more or less well off depending on their relative shares of ownership in dominant gas and power producers.
- The social objective of a price subsidy for electricity consumers is discarded.

The implications for international trade and importing economies would be as follows:

- A price subsidy on power exported to neighbouring economies is avoided.
- Consumers in neighbouring economies no longer see reduced power prices resulting from gas price subsidies, but they may still benefit from lower prices insofar as trading reduces overall average regional costs for delivered electricity.
- Power producers in neighbouring economies cannot complain of unfair competition since power producers in the exporting economies pay the same for gas fuel inputs as they do, except for differentials in transportation costs.

CONCLUDING OBSERVATIONS

It remains to be seen whether differences in regulatory structures for the electric power industry will in fact be a major obstacle to regional power trade in Northeast and Southeast Asia. In Southeast Asia, plans for regional power grid interconnections appear to be proceeding at a deliberate pace despite such differences. In both regions, moreover, there is a general trend towards regulatory reform and greater competition. Insofar as all economies in a region are moving toward more competitive systems, the issue of regulatory disparities may dissipate over time.

In theory, economies with more competitive power industries might be reluctant to accept competition from economies with less competitive power industries whose generators retain market power to cross-subsidise generation with revenues from transmission and distribution, or whose generation is subsidised by low gas prices from a vertically integrated gas monopoly. In reality, however, it is far from clear that the less competitive economies will wish to subsidise power for export through either gas price subsidies or electric price cross-subsidies, since such subsidies are costly. It is also far from clear that competitive power producers will fear competition from state-owned enterprises whose cost structures have not yet been slimmed by competitive pressures.

It also might seem that economies with less competitive power industries would fear competition from lower-cost generators abroad. But many governments are moving towards greater competition in order to lower the cost of electricity to domestic consumers, so they may actually welcome competitive pressure from abroad to spur competition at home. Moveover, even economies with less competitive power systems often possess substantial undeveloped energy resources which can be developed at a competitive cost, with the help of foreign capital, if a way exists to market them. By supporting the development of power grids through which these resources can be marketed abroad, such economies can therefore give a major boost to their economic growth. They may well choose to do so despite the possible risks of foreign competition.

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