Chapter 8

Assessment of Power Trade Benefits from Hydropower Projects in Lower Mekong River Basin

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September 2014

This chapter should be cited as
Piseth, C. and C. Sophearin (2014), 'Assessment of Power Trade Benefits from Hydropower Projects in Lower Mekong River Basin', in Han, P. and F. Kimura (eds.), *Energy Market Integration in East Asia: Energy Trade, Cross Border Electricity, and Price Mechanism*, ERIA Research Project Report FY2013, No.29.Jakarta: ERIA, pp.193-239.

CHAPTER 8

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The exchange of power between countries is regarded as economically beneficial since they offer opportunities for the optimum use of combined resources. This is especially the case when a hydropower-dominated supply system can be connected to a thermal power-dominated system due to the different and complementary characteristics of the two systems.

Hydropower in the Greater Mekong Subregion (GMS) has an enormous potential, on both large and small scale, to address regional energy requirement in significant capacity and the region has various experiences in regional power trading with the development of privately owned and financed cross-border hydropower project.

This research consists of three parts. The first part reviews the experience and lessons learned from the Regional Power Trade and Hydropower Development of Greater Mekong Subregion. It comprises two sections where section 3 presents an overview of power demand and supply in GMS countries, while section 4 reviews the hydropower development in the GMS. The second part focuses on determining benefits (economic benefit, and CO_2 emission reduction) accruing to each country by explaining the value of avoided generation costs and the annual cost of the hydropower project. This part is found in section 5 where the results of power benefit assessment are presented. The third part presents the key lessons learned and main challenges in GMS power trade and provides recommendation and policy implication for its smooth implementation. This part consists of sections 6, 7, and 8 where main the challenges and lessons are presented, followed by conclusions and recommendations.

The research found that the main mechanism for power trade in the GMS would be based on large-scale hydropower generation. To attract more investors and reduce investment risk in hydropower development, there is a need to refine investment costs, acquire hydrological data, and mitigate social and environmental impacts. Inter-governmental joint investments and the involvement of international financial institutions (IFIs) can also foster the necessary legal and legislative frameworks and enhance investment flow into an energy-export market. The Regional Power Coordination Center (RPCC) will play an important role in coordinating and accelerating the regional power trade for regional market rule comprising agreed rules and indicative planning priority of interconnection.

Keywords: hydropower, power trade, power supply benefit, power export benefit, economic benefit, Cambodia, Lao PDR, Myanmar, Thailand, Viet Nam, Guangxi, Yunnan, LMB, and GMS.

Introduction

Background

Energy cooperation in the Greater Mekong Subregion (GMS) began as part of the GMS Economic Cooperation Program launched in 1992. The GMS comprises Cambodia, the Lao People's Democratic Republic (Lao PDR), Myanmar, Thailand, Viet Nam, and the Guangxi Zhuang Autonomous Region and Yunnan Province of China.

Before 1992, at the start of the GMS program, the only significant power transmission links in the GMS were those between the Lao PDR and Thailand for the export of Lao PDR hydropower to Thailand. These consisted of double- and single-circuit 115 kilovolt (kV) lines to northeast Thailand from the Vientiane networks when the Lao PDR commissioned Nam Ngum 1 hydropower plant in 1971, and the single-circuit 115 kV line connecting the Lao PDR's southern grid to the Thai system in 1991 to deliver power from the Xeset hydropower plant (ADB, GMS-2012).

So far, power trade is only happening on a bilateral basis through transfer between the grid of producer and the consumer countries. The power being traded is mostly generated by hydropower plants and sold under power purchase agreements (PPAs) designed on a per project basis. Total electricity trade is 34,139 gigawatt-hour (GWh) in the GMS region where China, Lao PDR, and Myanmar are exporters while Thailand and Viet Nam are the main importers (ADB, RETA 6440- 2010).

While the first decade of subregional energy cooperation served primarily to advance planning and policy and institutional coordination, GMS energy cooperation also facilitated the implementation of high-priority power project with subregional impacts. Within the first decade, two hydropower plants in the Lao PDR exporting power to Thailand were implemented with private sector participation and ADB assistance (ADB, GMS-2012). For the second decade, the GMS program saw a quickened pace of project implementation by GMS governments with donor and development partner assistance and private sector initiative. Various other power generation and associated transmission projects in the GMS have also been developed. Among these are the generation and associated interconnection project in the Lao PDR and Myanmar that are intended for regional power trade, including the ongoing construction of the coal-fired Hongsa plant (1,800 megawatts [MW]), the various new hydropower capacity in the Lao PDR, and the completed Shewli-1 (600 MW) and Dapein-1 (240 MW) hydropower plant in Myanmar, which is now dispatching power to Yunnan province in China (ADB, GMS-2012).

At the moment, the framework for developing the GMS energy market integration (EMI) has taken through the Regional Power Trade Coordination Committee (RPTCC), which consists of two working groups—Working Group on Performance Standards and Grid Code, and Working Group on Regulatory Issues. The other approach of GMS regional power trade is to expect for the finalisation of the bidding that will decide who will host the Regional Power Coordination Center (RPCC), headquarter, the permanent, dedicated center envisioned to coordinate power trade in the GMS and to fully implement the Regional Investment Framework (RIF) for energy sector pipeline.

Objective

This paper aims to draw the lessons learned from two decades of cooperation of GMS power trade and interconnection. Its main purpose is to prove that hydropower could play an increasingly important role in the EMI of the GMS in the near future, serving as the answer to the rapidly growing demand for energy in the GMS countries while providing an alternative to dependency on fossil fuel. The result from this research will contribute to the EMI studies by providing policy analyses and recommendations to leaders and ministers at regional meetings, such as the East Asia Summit (EAS) Energy Ministers Meeting (EMM), the ASEAN Summit, and the EAS.

Structure

This paper consists of three sections. The first section focuses on the literature review by going through the experiences and lessons learned from the Regional Power Trade and Hydropower Development of Greater Mekong Subregion. The second section determines the benefits (focusing on net economic benefit, and carbon dioxide [CO_2] emission reduction) accruing to each country by explaining the value of avoided generation costs and the annual cost of the hydropower project. Finally, the third section explores the key lessons learned and main challenges in GMS power trade in order to provide policy implication and recommendations for the smooth implementation of EMI in the GMS region.

Methodology

This research uses Power Evaluation Model (PEM) for calculating economic benefit from avoided cost of generation incurred from hydropower replacement to thermal power plant. The PEM model was made by the Mekong River Commission's Basin Development Programme (MRC-BDP) in 2008 for the assessment of basin-wide development scenarios during Phase 2 (MRC-BDP 2, 2010). This research focuses on the assessment of the net economic power benefits from shared hydropower projects between exporter and importer countries in the GMS region. The methodology details are described in **Annex 1.**

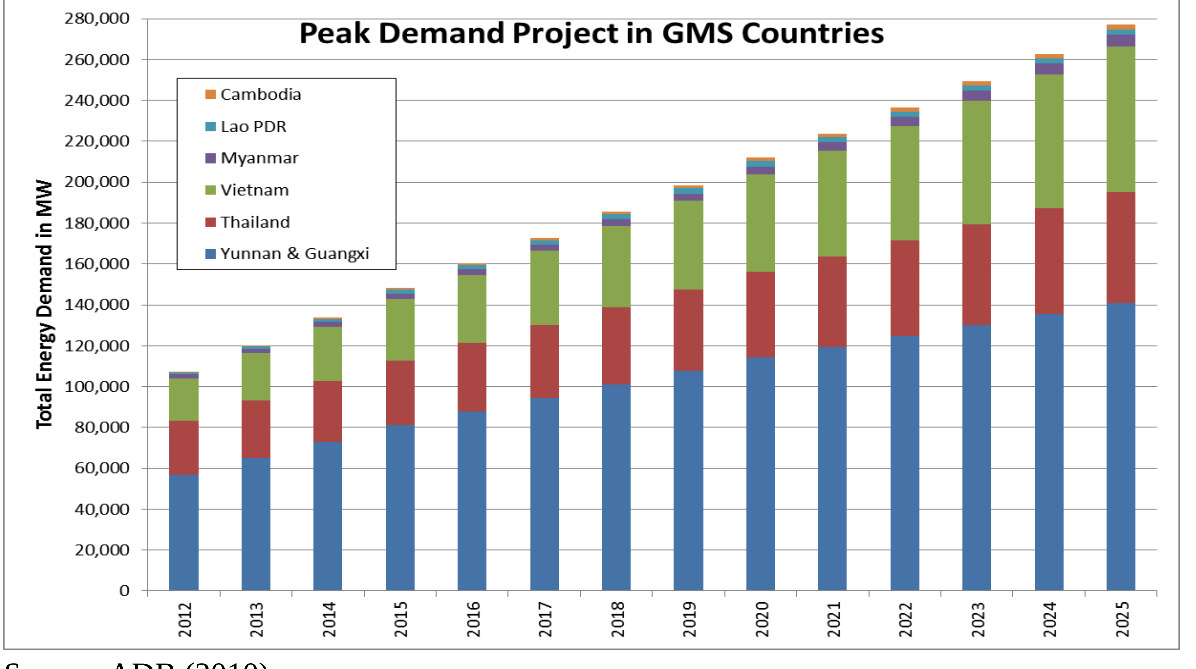
Overview of Power Demand and Supply in the GMS

Power Demand Projection in THE GMS

There are several factors driving electricity demand in the GMS. The rapid pace of export-led growth in the region comes on top of efforts to improve and expand electricity access in rural area, amid trends toward urbanisation, diversification of regional economy, and rapid population growth.

Peak demand in the GMS, which stood at 83 gigawatts (GW) in 2010, is expected to more than triple to 277 GW by 2025. Thailand has the largest power system and currently accounts for 29% of peak power demand. Viet Nam, the Guangxi Zhuang Autonomous Region, and Yunnan province each carry about 20% of the peak demand. Simulation undertaken for the latest update of the GMS Master Plan for power interconnection forecasts that by 2025, Thailand's share of peak power in the GMS will decrease to about 20%, while Viet Nam's rapid economic growth will increase its peak load share to a quarter of GMS peak load. The combined demand of the Guangxi Zhuang Autonomous Region and Yunnan Province in China will continue to account for about half of all the GMS peak demand. Thailand, Viet Nam, and China will account for 96% of the GMS peak demand by 2030 with greater reliance on gas and coal-fired electricity generation. Meanwhile, the power requirements of Cambodia, the Lao PDR, and Myanmar will similarly grow but are expected to retain only about 4% share of the subregion's overall power demand. The latter three countries have substantially smaller national power system but are expected to benefit from developing power export to the rest of the GMS, considering their substantial energy resource potential relative to their electricity needs (ADB, ICEM, GMS-2013).

Figure 8.1: Total Peak Demand Projections in GMS Countries

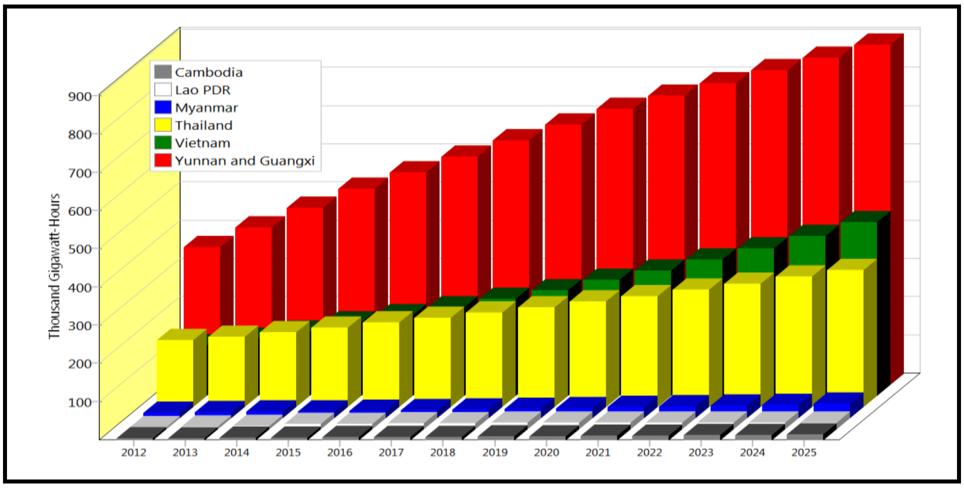


Source: ADB (2010).

Projected Energy Demand in the GMS

Electricity demand growth rates in many Mekong countries are among the highest in the world. The demand is mainly located in China, Thailand, and Viet Nam. By 2025, the total energy demand in the GMS will be 1,757 terawatt-hour (TWh) of which Yunnan and Guangxi of China account for 50%, Viet Nam for 25%, Thailand for 20%, and the remaining 5% shared by Myanmar, Lao PDR, and Cambodia (ADB, RETA 6440-2010).

Figure 8.2: Energy Demand Projection of GMS Countries (in GWh)



Source: ADB (2010).

GMS Energy Resources Endowment

In 2012, the energy resources in the GMS was estimated about 229 GW of annual hydropower potential along with proven reserve of about 1.2 billion cubic metres of natural gas, 0.82 million tons of oil, and 28 billion tons of coal. While the subregion is well-endowed with energy resources, these are unevenly distributed (Table 8.1).

Table 8.1: GMS Energy Resources Endowment

Countries/ Provinces	Hydropower (MW)	Gas (billion m^3)	Oil (million tons)	Coal (million tons)
Cambodia	9,703	N/A	N/A	10
Yunnan	104,370	N/A	N/A	23,994
Guangxi	17,640	N/A	173	2,167
Lao PDR	17,979	N/A	N/A	503
Myanmar	39,669	590	7	2
Thailand	4,566	340	50	1,239
Viet Nam	35,103	217	626	150

Note: N/A = not applicable
Source: ADB (2012).

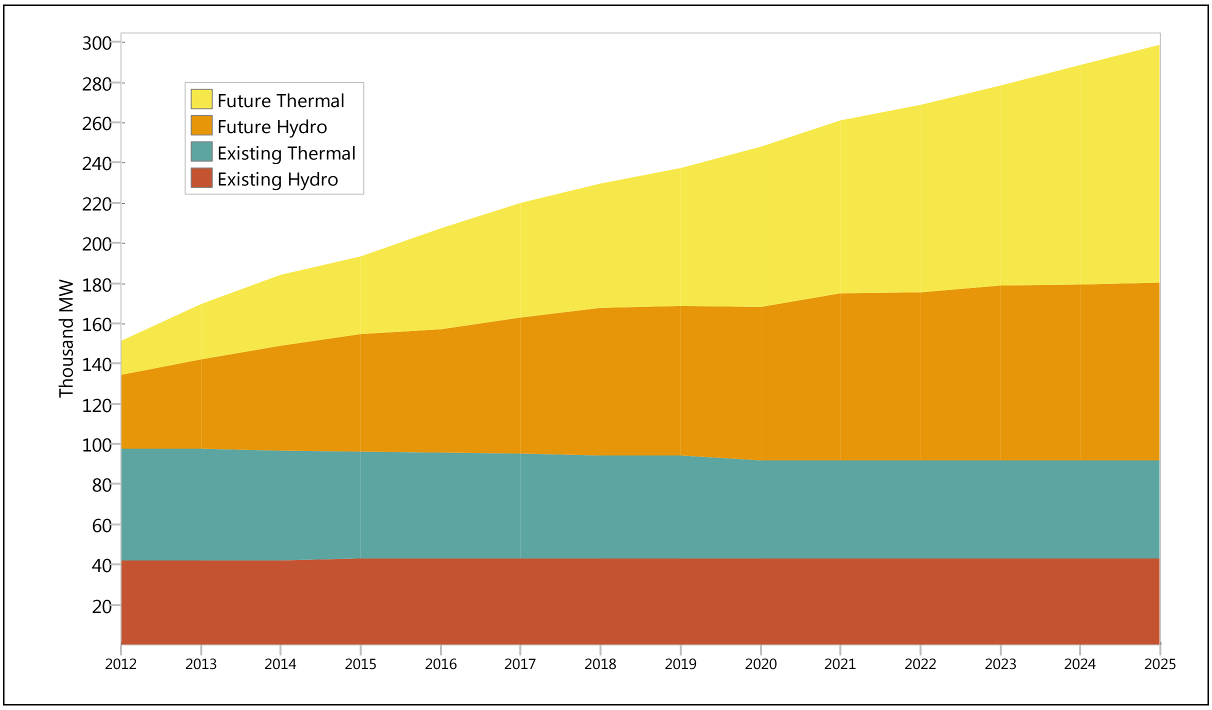
The Lao PDR, Myanmar, Viet Nam, and the two China provinces account for 94% of the hydropower resources in the region. The hydropower potential of the Lao PDR and Myanmar is substantial compared to their size and expected power need, while Viet Nam's hydropower potential is concentrated in Northern Viet Nam. Myanmar, Thailand, and Viet Nam possess natural gas deposits, Viet Nam has mostly oil reserves, and Yunnan Province of China holds the main coal deposit. Cambodia, Thailand, and the two China provinces have mainly been net energy importers, while the Lao PDR, Myanmar, and Viet Nam are net energy exporters to other GMS countries and the rest of the world. Similarly for electric power, the Lao PDR and Myanmar have been generating electricity for export beyond the supply requirement of their grid-connected domestic consumers (ADB, GMS-2012).

Development of The Power Sector in The GMS

Total installed generation capacity is projected to almost triple in the GMS over the period from 2012 until 2025 while the number of thermal and hydropower plants is expected to double over this period. Nationally, the projected capacity expansion is dominated by growth in Yunnan and Guangxi, where installed capacity is expected to more than double—from 53 GW in 2012 to 136 GW by 2025—representing 40% of the total increase across the GMS.

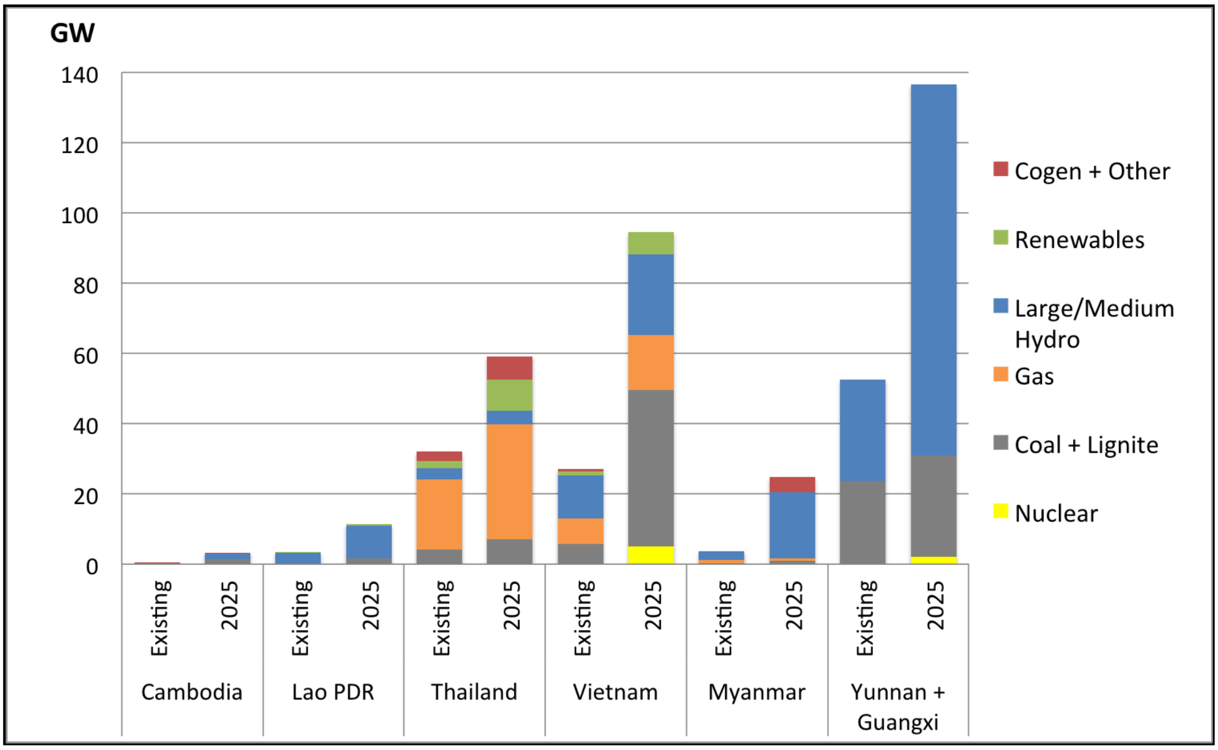
The projected expansion in large hydro capacity is largely due to planned projects in Yunnan, which represents an increase in hydro installed capacity of 77 GW or 69% of the total increase in the GMS. Installed large hydro capacity in Myanmar is projected to rise by 16 GW, in the Lao PDR by 15 GW, and in Viet Nam by 11 GW (ADB, RETA 6440-2010).

Figure 8.3: Installed Capacity Projection in the GMS by 2025 (without data from Myanmar)



Source: ADB (2010)

Figure 8.4: Projected Installed Capacity by Country in the GMS, Current PDPs Scenario



Note: GW = gigawatts, PDPs = power development plans
Source: ICEM and ADB (2013)

The technology with the largest expansion in both installed capacity and in number of plants is large hydro, followed by coal-fired plants. While renewables capacity grows more rapidly in percentage term than either of these, the absolute increase in renewables capacity is lower than those of these technologies.

Table 8.2: Projected Installed Capacity by Technology in the GMS, Current PDPs Scenario

Fuel Type	Existing (2012)		**Projected (2025)**		**Increased (2012-2025)**		
	MW	# Plant	**MW**	**# Plant**	**MW**	**%**	**# Plant**
Nuclear	0	0	7,160	4	7,160	0	4
Coal + Lignite	34,058	41	84,341	83	50,283	148	42
Gas	27,959	39	52,287	54	24,328	87	15
Large hydro	49,727	116	160,963	254	111,236	224	138
Renewables	3,533	n.c	16,475	n.c	12,942	366	n.c
Cogen + Others	3,689	16	8,006	6	4,317	117	-10
Total	**118,966**	**212**	**329,232**	**401**	**210,266**	**157**	**18**

Note: MW = megawatts, n.c = Not Count, PDPs = Power Development Plans
Source: ICEM and ADB (2013)

Review of Power Demand and Supply in Yunnan and Guangxi provinces

The electricity consumption per capita (kWh/person) in China is the highest among GMS countries. In 2011, the electricity consumption per capita was 2,600 in Yunnan and 2,394 in Guangxi. The peak demand of Guangxi and Yunnan will be 140 GW in 2025 with 40 GW export to Guangdong. The need for new additional capacity is about 3,500 MW per year. Although Yunnan has huge potential of hydropower, it will not be sufficient to cover the demand up to 2025.

The total supply for Guangxi in 2012 was 115.4 TWh with a peak demand of 20 GW (an increase of 3.8% and 8.1%, respectively, from 2011). By 2030, supply is projected to increase to 396 TWh and peak demand to 60.6 GW (an average annual increase of 7.5% and 6.7%, respectively). Total installed capacity within Guangxi in December 2012 was 30.4 GW. By 2030, this is projected to increase to 86 GW installed capacity within Guangxi with a 19

GW imported capacity. The largest increase will be in nuclear generation (from zero to 20 GW) and in thermal and gas generation (from 15 GW to 37 GW).

Yunnan currently has 10 coal-fired power plants with total installed capacity of 11.2 GW, and 14 hydropower plants with total installed capacity of 13.6 GW. By 2025, these will increase to 11 coal-fired plants with total installed capacity of 12.4 GW, and hydropower plants with total installed capacity of 88.7 GW (ADB, ICEM, GMS-2013).

In China, the investment cost of coal-fired steam thermal power plant is lower than in other GMS countries, but exposed to restrictions due environmental concern. Export to other GMS countries based on coal-fired power supply is not realistic. China will have a very limited export role except for local situations where there is temporary power surplus or for purposes of cooperation. The promising large volume of power export from China to Viet Nam does not look realistic. China has already imported hydropower from Myanmar and planned to import more hydropower generated from Myanmar and the Lao PDR. The import will allow China to save coal, reduce CO_2 emission, and to reach the target of supplying power to Guangdong (ADB, RETA 6440-2010).

Review of Power Demand and Supply in Thailand

The electricity consumption per capita in Thailand was 2,180 kWh/person in 2011.Thailand will require 54 GW by 2025, which is about 2,500 MW increase per year. In 2012, the country's demand was 26.12 GW. By 2030, the demand forecast is 52.25 GW. About 80% of electricity produced in Thailand comes from natural gas. A higher proportion of imported liquefied petroleum gas (LPG) is needed as Thailand's production of natural gas is insufficient for future requirements. Natural gas used in Thailand primarily comes from three sources: the Gulf of Thailand, 79%; Myanmar, 18%; and 3% imported as liquefied natural gas (LNG) from countries like Indonesia, Nigeria, Peru, Qatar, and Russia. However, the worst-case scenario prediction made by Economic Intelligence Center (EIC) estimates that the Gulf of Thailand will run out of natural gas by 2020. There are also risks from the possible failure to renew gas contract with Myanmar, which should end by

2030, as Myanmar's electricity consumption needs are also growing fast. Although Thailand has plans to import natural gas through pipeline from Cambodia, these plans still lack certainty from either government. Thus, it appears that Thailand will have to rely on importing a lot of LPG (SCB-2013).

Such supply risk is mitigated through diversification of generation mix (coal, nuclear, in addition to natural gas), power import sources (Lao PDR, Myanmar, Malaysia, Cambodia, and China), and fuel import sources. Significant level of power dependency is 14% of peak demand imported in 2025 (Power Development Plan 2010-Revision 2), of which 5.5 GW is from the Lao PDR and 1.9 GW from Myanmar. Going beyond 15% would require a careful analysis of balance between benefit and risks. Power import will reduce the use of natural gas and coal (ADB, RETA 6440-2010).

Review of Power Demand and Supply in Viet Nam

In Viet Nam, the electricity consumption per capita was 1,228 kWh/person in 2011. The peak demand will increase by 4,000 MW per year in 2025 to reach 71 GW. Viet Nam's power demand will catch up with Thailand's demand in 2017. The total installed capacity of power plant will be 75 GW by 2020 and 94 GW by 2025. Full national hydropower potential will be put in operation before 2025 by domestic power demand, especially priority multi-purpose projects such as flood control, water supply, and electricity production that will bring the total installed capacity from 9.2 GW at the present to 17.4 GW by 2020.

By 2020, electricity generation capacity using natural gas will be 10.4 GW, producing about 66 TWh of electricity, and accounting for 20% of electricity production. It is expected that in 2030, the total capacity of thermal power plant using natural gas will be 11.3 GW, producing 73.1 TWh of electricity, and accounting for 10.5% of total capacity. To diversify fuel source for electricity production, Viet Nam will develop power plants using LNG. In 2020, electricity generation capacity using LNG will be about 2 GW, and by 2030, the capacity will be about 6 GW (Government of Viet Nam, 2011).

Viet Nam has been considering developing nuclear power for peaceful purposes based on modern, verified technology since 1995, and firm proposals surfaced in 2006. However, in January 2014, it was reported that Viet Nam had decided to delay construction by six years. The first nuclear power plant will put in operation by 2020. By 2030, installed capacity of nuclear power will be 10.7 GW, producing 70.5 TWh (accounting for 10.1% of electricity production).

Viet Nam will make use of domestic coal resource for the development of thermal power plants and will prioritise the use of domestic coal for thermal power plant in the Northern region. By 2020, the total coal thermal power installed capacity will be 36 GW, producing 156 TWh (accounting for 46.8% of total electricity production), and consuming 67.3 million tons of coal. By 2030, the total installed capacity for coal power plant will be 75 GW, producing 394 TWh (accounting for 56.4% of total electricity production), and consuming 171 million tons of coal. Due to the limitation in domestic coal production, building and putting power plants using imported coal into operation from 2015 is to be considered. Viet Nam has become a net coal importer by 2012. There are plans to reduce gradually its coal export.

Viet Nam currently exports power to Cambodia due to shortage of supply, with economic power exchanges as the main rationale. Viet Nam planned to import hydropower, especially from the Lao PDR and then Cambodia and China. It is expected that in 2020, imported electricity capacity will be about 2.2 GW and approximately 7 GW in 2030. The level of power dependency is 7% of the peak demand which was reported in the Viet Nam National Master Plan for Power Development Plan 2011-2020 with the vision to 2030 (Master Plan VII). The maximum level of power import was accepted with 10% of peak demand and imported-power will reduce imports of coal and natural gas.

Review of Power Demand and Supply in Lao PDR

Electricity demand growth in the Lao PDR registered a significant increase in the past few years. In 2011, the electricity consumption was 402 kWh/person, produced energy per capita was 1,570 kWh/year, and exported energy per capita was 1,360 kWh/year. The major consumptions come from mining industries, manufacturing, commercial business, services, and rural electrification projects. To date, there are two independent network systems in the Lao PDR—the domestic supply network (Electricité du Laos [EDL], domestic independent power producer [IPP], and off-take from exporting IPP), and the exporting network (exporting IPP) to neighbouring countries, i.e., Thailand, Viet Nam, and others.

By 2021, the domestic demand forecast will be about 3,570 MW with the annual average growth of capacity at 235 MW. In the Lao PDR, hydropower plants provide electricity for both domestic consumption and for export to Thailand and Viet Nam. The total installed capacity was 2,570 MW in 2011 (all from hydro) and forecast to reach 12,500 MW in 2020. An additional 2,623 MW of capacity is expected, involving 12 power plants for both domestic consumption and export, and these are in various stages of construction. In addition, 60 new hydropower plants are in various stages of study, approval, and design. By 2020, when all of the 12 projects presently under construction have been completed, it is expected that the Lao PDR will have harnessed about 8,100 MW of its 20,000 MW of potential capacity. Lao PDR has about 13,5000 MW of hydropower potential with cost lower than US$0.05/KWh that has been planned primary for export to Thailand and Viet Nam, and possibly to China (EDL-DOE, 2011).

As to coal and lignite, the coal reserve of the Lao PDR is estimated to be about 600-700 million tons, occurring mostly as lignite with smaller amount of anthracite. In 2011, the first lignite-fired power plant (Hongsa Lignite Thermal Power Plant) was put under construction and is expected to be completed in 2016. The total installed capacity of this plant is 1,878 MW of which 1,473 MW will be exported to Thailand, while the remainder will be used for domestic supply. Moreover, the Kaleum thermal power plant with installed capacity of 600 MW is also considered for export (ADB, ICEM, GMS-2013).

Review of Power Demand and Supply in Cambodia

Electricity demand in Cambodia is growing rapidly at an annual average growth rate of 16% for electricity supply and 18% for electricity demand in the past five years from 2009 to 2013. In 2012, the annual electric energy consumption per capita was 190 kWh and electricity supply was a mix of

20% imported electricity (11.8% from Viet Nam, 8.1% from Thailand, 0.1% from the Lao PDR), 46% heavy fuel oil, 31% hydropower, 2% coal, and 1% from other sources. The energy demand is projected to reach 2,750 MW by 2020. As of January 2014, the total installed capacity was 1,662 MW including that of a new coal power plant of 100 MW. Cambodia is currently eager to increase its electricity generation capacities from hydropower and coal power plants to decrease its import dependency and reduce the generation for fossil fuel. Cambodia has a hydropower potential of about 10,000 MW; only seven hydropower plants with a total capacity of 1,326 MW were put in operation and some are under construction, which are expected to be completed by 2017. There is a potential of 2,600 MW of hydropower projects with a cost lower than US$0.05/kWh, located on the mainstream of Mekong River that can be exported to Viet Nam and Thailand. Due to fisheries, resettlements, and land issues; lack of transparency; and lack of environmental and social impact assessment and community consultations, this large-scale potential is highly controversial and, therefore, is unlikely to be developed (ADB, RETA 6440-2010).

Cambodia has planned to install 1,000 MW of coal power plant by 2020. The first coal-fired power plant with a capacity of 100 MW was put in operation in February 2014. Other plants with a total of 400 MW capacity are expected to complete the 100 MW target for each year from 2014 until 2017. The second phase was planned with 500 MW and the expected operation is from 2017 until 2020. Another coal-fired power plant (1,800 MW) is planned to be built in Cambodia's border under a US$3 billion joint-venture agreement with Ratchaburi Electricity Generating Plc. This project has been planned to sell 90% of the power generated (1,600 MW) to Thailand and the remaining 10% will be used for domestic supply (EAC, 2013).

Review of Power Demand and Supply in Myanmar

The electricity demand in Myanmar is increasing rapidly with an average increase of 15% between 2013 and 2016. In 2013, power demand was 1,850 MW with total generation at 1,688 MW. The demand is projected to reach 19,216 MW with installed capacity of 24,981 by 2030. For its energy supply, the country primarily relies on hydropower (75%), followed by gas (22%), and coal (3%). Myanmar has abundant energy resources, particularly hydropower and natural gas (ADB, GMS- 2012).

Myanmar has identified 92 potential large hydropower projects with a total installed capacity of 46,101 MW. Only 20 hydropower plants with a total capacity of 2,780 MW have been commissioned by 2013. The Ministry of Electric Power (MOEP) is planning to build another 13 hydropower plants by 2020 with a total capacity of 2,572 MW while an additional 44 projects are planned as joint ventures with foreign investors, totalling approximately 42,146 MW. Electricity produced by hydropower is considered very cheap compared to other alternative sources. There are 28,000 MW of hydropower potential at a cost of just about 2.5 cents in US dollar per kWh, some of which have already been exported to China, and more exports are being planned for China, Thailand, India, and Bangladesh (Doran, *et al*., 2014).

There are 33 major coal deposits with estimated total reserves of 488.7 million tons in various categories. Only 1% of this estimate potential, however, has been confirmed. According to the 30-year plan prepared in 2007, coal production is scheduled to increase by 16% annually reaching 2.7 million tons by 2016 and 5.6 million tons by 2031. In 2011, a total of 0.7 million tons of coal was used domestically, of which 42% was for power generation, 52% for cement and other industrial uses, and 4% for household (cooking and heating) use. The first coal-fired plant with 120 MW was completed in 2002. Myanmar has planned to construct three more coal power plant with a total capacity of 876 MW (ADB, GMS-2012).

Myanmar's hydrocarbon reserves are predominately in the form of natural gas, the reserve of which is estimated to be 334 BCM. In 2010, Myanmar exported 8.81 BCM of natural gas, significantly more than that of Malaysia at 1.45 BCM, and follows Indonesia with 9.89 BCM. Myanmar, however, is a net importer of oil. Domestic gas demand in 2011 was about 60 BCM of which 60% was supplied to 10 gas-fired power plants. Another 10 gas-fired power plants with a total capacity of 1,720 MW are planned to be put into operation between 2014 and 2017 (ADB, GMS-2012).

Review of Hydropower Development in the GMS

As of 2012, there is some 49,000 MW of hydro capacity in the GMS, of which 20,000 MW is in the Lower Mekong Basin (LMB) countries (Table 8.3). According to current power development plans (PDPs), this is set to triple by 2025.

Table 8.3: Overview of Hydropower Development in the GMS

	Installed Capacity			**Number of Projects**		
	Existing	PDP	Capacity additions	Existing	PDP	Capacity additions
	2012	2025	2013-2025	2012	2025	2013-2025
	[MW]	[MW]	[MW]	[#]	[#]	[#]
Cambodia	206	1,658	1,452	2	9	7
Lao PDR	3,150	9,456	6,306	14	53	39
Thailand	2,675	2,675	0	6	6	0
Myanmar	2,660	18,756	16,096	19	39	20
Viet Nam	11,711	17,002	5,291	46	85	39
Total LMB	20,402	49,548	29,145	87	192	105
Guangxi	13,581	88,672	75,091	14	39	25
Yunnan	15,244	16,844	1,600	14	15	1
Total GMS	49,227	155,064	105,836	115	246	131
Mekong	3,652	10,786	7,134	18	60	42
Others	45,575	144,277	98,702	97	186	89

Note: GMS = Greater Mekong Subregion, LMB = Lower Mekong Basin, MW = megawatts, PDP = power development plan (Note: excludes pumped storage and small hydro);
Source: ICEM and ADB (2013).

As shown in Table 8.3, the future development of hydro in the region is also very uneven—at the one extreme, no new large hydro projects are likely to be developed in Thailand, while at the other extreme, projects at 75 GW are under development in Guangxi, and 16 GW in Myanmar. The pace of hydro development in Viet Nam has already slowed, as all the large projects have now been developed, and planners are looking to the Lao PDR for additional hydro projects to provide peaking power where it competes with Thailand for additional export projects. Whether this is achievable will depend on the following three factors:

- If the costs of hydro generation will continue to be significantly below that of peaking power supplied by gas;
- If the incremental finance requirement can be mobilised (the typical hydro investment for new projects is US$2,400/kW; that for CCGT is only US$850/kW); and
- If and when the increasing public opposition to hydro power due to environmental and social issues—which already effectively prevented the further development of large hydro projects in Thailand—will expand to the other countries in the region.

The extent to which this large hydro-export potential can be realized will depend on the extent to which projects are commercially feasible. This depends on the following four criteria:

- Potential investors make a financial return that reflects the risks assumed.
- Projects can be financed.
- Host country governments can extract adequate resource rents.

Importing countries can buy hydro power at lower cost than the next best alternative (which in the case of both Thailand and Viet Nam will likely be gas combined cycle thermal generation).

The four parties involved in a large export project—the developer, the lenders, the host country, and the importing country—all have conflicting interests. The extent to which a commercially satisfactory compromise can be reached for all of the identified potential projects is difficult to judge. There are a number of examples in the international experience where hydro export projects are effectively blocked because one or more of the four parties have unreasonable expectations. One classic example is the unreasonable expectation of the Government of Nepal about the value of peaking power from Nepalese hydro export projects into the Indian power market—expectations that constitute one of the main causes for the lack of progress in implementing such projects. By contrast, the Lao PDR has been much more successful in finding the right balance of these commercial interests, though many claim that the environmental and social interests have been inadequately reflected in Lao PDR's export projects (ADB, ICEM, GMS-2013).

Trends in Hydropower Development in The GMS

Several trends can be identified from the inventory of proposed projects. The installed capacity of projects is increasing, from an average of 428 MW (covering all GMS countries) in existing projects to 808 MW for all projects added between now and 2025. In Viet Nam, the average size is expected to decline from 255 MW to 136 MW (Table 8.4). In Guangxi, the average project size will increase from 970 MW to 3,000 MW (ADB, ICEM, GMS-2013).

For many reasons, the next decade is likely to see significant development of pumped storage. In Viet Nam, while conventional large hydro additions are forecast in its Power Development Plan at some 5,200 MW, another 4,200 MW of pumped storage is envisaged. This is being driven by three main factors. *First*, with prospects for additional domestic gas seen as uncertain, pumped storage is seen as considerably less expensive than combined cycle gas turbines (CCGTs) using imported LNG. *Second*, with many base load imported coal and nuclear projects seen as necessary beyond 2020, and with increasing daytime air conditioning load, pumped storage is seen as a suitable balance mechanism to meet daily load variations. This is unlikely to be seen in Myanmar, the Lao PDR, and Cambodia where domestic load will remain modest compared to potential export markets. And *third*, the environmental impacts of pumped storage are seen as relatively manageable, particularly where an upper reservoir—whose active storage and surface area can be quite small—can be sited adjacent to a large existing conventional hydro project (ADB, ICEM, GMS-2013).

Table 8.4: Average Installed Capacity (MW)

Country	2012	2015	2020	2025	All New
	[MW]	[MW]	[MW]	[MW]	[MW]
Cambodia	103	182	203	184	207
Lao PDR	225	156	167	178	162
Thailand	446	446	446	446	
Myanmar	140	118	117	481	805
Viet Nam	255	228	205	200	136
Total LMB	235	197	186	258	278
Guangxi	970	2,391	2,345	2,274	3,004
Yunnan	1,089	1,089	1,123	1,123	1,600
Total GMS	428	624	583	630	808
Mekong	203	158	171	180	170
Others	470	742	722	776	1,109

Note: GMS = Greater Mekong Subregion, LMB = Lower Mekong Basin, MW = megawatts

Source: ICEM and ADB (2013)

Hydropower Development and Implementation Models

The additional 100 GW hydro capacity from 2013-2025 represents an enormous financing requirement. Even excluding the capacity in China, the remaining 29 GW in LMB countries represent an investment requirement of some US$70 billion. Even if the environmental impacts can be mitigated, mobilising this investment will be formidable. Notwithstanding IPP interest in a number of hydropower projects in the region, mobilising private capital for thermal projects is much easier; with much shorter construction periods and fewer environmental obstacles, the risk perception of hydropower projects remains even for projects where tunnelling risk is relatively low (Doran and Christensen, 2014).

The first implementation model for large projects is the public-private partnership (PPP), where a host country government has a significant equity stake, and which enables access to international financial institutions (IFIs) for a significant part of the debt (as in the case of Nam Ngum 3, to be financed by ADB), or access to partial risk guarantees (PRGs) (as in the case of Nam Theun 2). It is a policy of the Government of Lao PDR that it should have a share in the equity of electricity projects developed under a concession agreement (though one of the issues is the extent to which it has the ability to bear the equitable share of the up-front development costs, which some memoranda of understanding (MOU) allow to be deferred to financial closure (Doran and Christensen, 2014).

A typical equity consortium involves several parties, in the case of export projects, they most often include entities from the country to which the electricity will be exported. IFI participation in such project (or even participation in equity from the International Finance Corporation (IFC) or the ADB private finance arm) provides comfort to both lenders and equity holders, lowering the risk premiums for the remaining finance and equity tranches.
The involvement of the IFIs is contingent upon meeting their safeguards requirements, which include, among others, ensuring certain minimum standards for adequate safeguard provisions for project-affected persons in project areas. Thus, securing IFI finance for such PPPs is not only a matter of finance availability but also of mitigating actual or perceived reputation risks (an issue that is particularly sensitive in the case of the World Bank). The recent experience of the World Bank in the region, for example, in the case of the 260 MW Vietnamese Trung Son Hydropower Project, suggests that careful preparation, engagement of the local community, and complete transparency in the appraisal process enabled bank financing without much difficulty, and lead to successful and sustainable projects. It seems likely that in Viet Nam, the World Bank will be seen particularly as a source of funding for pumped storage projects.

The World Bank's safeguard requirements on downstream impact have particular relevance to the Mekong River Mainstream projects. These bank-financed investments involve water abstraction, release of water or material into water, or hydrological impacts (regardless of scale) on a water body that is shared by two or more countries (aquifers, open seas excluded; except in the rehabilitation of an existing scheme); and require notification and no objection from downstream residents with riparian rights. If one or more of the downstream parties do object, then at the very least, time-consuming studies will need to be conducted to refute or concur with their grounds for objection, before bank financing can be approved (MRC-SEA, 2010).

The second implementation model relies entirely on commercial financing, without IFI participation. For example, the Xayaburi project (1,260 MW) in the Lao PDR, which exports to Thailand, is financed by a consortium of Thai commercial banks whose equity participation includes Thai and Laotian private companies, plus the Government of Lao PDR. A number of domestic hydropower projects in Cambodia are also being developed by Chinese companies. This implementation model has the advantage (from the narrow perspective of investors) that they do not need to be concerned about IFI safeguards. Thus, backed by export credit and by increasingly strong private commercial banks, a new generation of IPP hydropower project developers based in Thailand, Malaysia, and China is gradually displacing IFIs and IPP developers based in Organisation for Economic Co-operation and Development (OECD) countries, which are increasingly encumbered by nongovernment organizations (NGOs) vocally opposed to hydropower development (EDL, 2011).

This is exemplified by Cambodia. All seven hydropower projects—(i) Kamchay, 193 MW, completed in 2011; (ii) Kirriom III, 18 MW; (iii) Lower Russei Chrum, 338 MW; (iv) Stung Tatay, 246 MW; (v) Stung Atay, 120 MW; (vi) Lower Sesan II, 400 MW; and (vii) Stung Chay Areng, 108 MW—are being developed by Chinese companies (EAC, 2013).

Financing Requirements for Hydropower Development in the GMS

A bankable power purchase agreement (PPA) is highly essential in considering commercial feasibility, the main determinant of bankability being the credit standing of the buyer. Fortunately, the two main potential buyers, the Electricity Generating Authority of Thailand (EGAT) and Electricity Viet Nam (EVN), have relatively good credit ratings and customer tariffs that are not excessively below marginal costs. The length complexity of PPA will be a function of the extent of involvement of foreign investors as well as the size of the project. The Nam Theun 2 (NT2) PPA (whose equity investors include the French EDF, Italian, and Thai companies) runs to over 600 pages. Also, this NT2 PPA would not have been signed without the partial risk guarantee (PRG) of the World Bank (Fraser, 2010).

The question of the remaining headroom for sovereign guarantees is difficult to assess, particularly in the case of the Lao PDR, and their absence will affect the investment supply cost through higher interest rates. In 2010, ADB financed (US$465 million) for the Nam Ngum 3 project, US$350 million will be provided without sovereign guarantees. The remaining US$115 million is sovereign loan (Fraser, 2010).

However, the entry into Lao PDR, Cambodia, and especially Myanmar (where the undeveloped potential is the largest in the region) of the Chinese EXIM Bank, and Chinese developers, is changing earlier perceptions of the difficulty of financing large hydro projects in the region in the absence of IFI finance. The NT2 project showed that large hydro projects could, indeed, be successfully implemented by the private sector (albeit with PRGs from IFIs). That the role of ADB and the World Bank will inevitably continue to decline in the GMS as a source of finance for generation projects should not, however, be seen as a failure of these institutions, but rather as a success—having fulfilled the role of an early catalyst—since their financial resources are much better directed to rural electrification, energy efficiency, and transmission & distribution, where commercial financing alternatives are not available.

Trends with Multilateral, Bilateral and Projects Specific Agreement in Power Trade

Governments in the GMS signed an Intergovernmental Agreement on Power Interconnection and Trade in 2003. Subsequently, a ‘road map’ to implement the agreement was prepared. This road map builds on a series of bilateral MOUs and agreements developed by the GMS governments over the past two decades to extend cross-border power trade between their respective countries. These bilateral MOUs authorise respective power entities in each country to negotiate PPAs for specific projects, which fit within the quantum of power under the bilateral MOU.

So far, Thailand has signed bilateral MOUs to buy up to 11,500 MW from its neighbor countries. In 2007, Thailand signed an MOU with the Lao PDR to purchase 7,000 MW, with China for 3,000 MW, and with Myanmar (MOU now expired) for 1,500 MW. Thailand and Cambodia also signed an MOU on power cooperation with unspecified capacity. Power exports from Thailand to Cambodia were 95 MW in 2013 and will increase to 135 MW in 2014. Thailand is projecting 5,427 MW in power interconnection purchases during the period 2013-2019, mostly from the Lao PDR, comprising 2,111 MW from completed projects and 3,316 MW from signed PPAs and projects under construction (RPTCC 15th, 2013).

Based on an MOU between Viet Nam's Ministry of Industry and Trade and Lao PDR's Ministry of Energy and Mines signed in March 2008, Viet Nam would invest in 31 projects with total installed capacity of 5,000 MW where a large part of the energy produced from these projects will be exported to Viet Nam. In the last Viet Nam PDP (Master Plan VII), the total power exchange with its neighboring countries, especially with Lao PDR, Cambodia, and China, is expected to be 2,200 MW in 2020 and imported electricity capacity will be approximately 7,000 MW in 2030. In May 2009, the Eletricité du Viet Nam and Electricité du Cambodge signed an electricity trading contract that Viet Nam would sell electricity to Cambodia at a capacity of 200 MW in 2010. The Government of Cambodia also agreed to sell its surplus power from hydropower project to Viet Nam during the wet season, but without indicating the capacity (ADB, RETA 6440-2010).

China is actively strengthening its cooperation with Viet Nam, Lao PDR, Myanmar, Thailand, and Cambodia with the objective of optimising resources allocation and utilisation. Since 2004, the China Southern Power Grid (CSG) has exported 1,100 MW to Viet Nam, 24 MW to the Lao PDR, and imported 483 MW from Myanmar. CSG indicated that it will import 10,000 MW from Myanmar between 2012 and 2030 of which 5,000 MW will come from hydropower in Irrawaddy and Salween River Basin. In June 2013, China and Thailand signed the MOU on Power Purchase Program from China to Thailand with transmission through Lao PDR (ADB, Laos-2011).

Myanmar signed an MOU with Thailand in 1997 for the trade of 1,500 MW of electricity, which expired in 2010 and has not been renewed. Thailand is reported to be in negotiation to purchase up to 10,000 MW of hydroelectricity from Myanmar over an unspecified time period. This MOU is linked directly to Salween dam projects, five proposed dam along the Salween River, which would have a combined capacity of more than 18,000 MW. Specifically, Thailand will receive most of the power of 7,110 MW from Tasang dam, which is planned along its border with Myanmar. Thailand, through its generating authority, the EGAT, is also planned to receive the majority of power generated of 1200 MW from Hatgyi dam, which is currently under construction and is expected to supply the Thai national grid by 2019. The Weigyi dam, which has a total capacity of up to 5,600 MW, is also planned to export to Thailand.

The Ministry of Power, Energy and Mineral Resources of Bangladesh is reported to negotiate for the purchase of 500 MW of hydropower from Myanmar by 2017. However, apart from this pending agreement, no other broad power trading MOUs are reported to be under consideration.

India's National Hydroelectricity Power Corporation (NHPC) signed an MOU with the Government of Myanmar in 2004 for the development of Tamanthi dam in Chindwin River with installed capacity of 1,200 MW. Of this generated hydropower, 80% will be supplied to India. A new agreement was signed in 2008 for a joint venture between the NHPC and Myanmar Hydroelectricity Power Department to develop the Tamanthi and Shwesayay dams.

So far, China is the largest financier of hydropower in Myanmar and has a number of MOUs signed for various power-trading agreements. Chinese state-owned enterprises are publicly involved in nearly every large-scale hydropower project, either at the advanced planning stage or under construction in Myanmar. Together, these projects represent 31,451 MW of potential generating capacity, a significant percentage of which will be exported to China. The largest of these project-specific MOUs was signed in 2007 between the Government of Myanmar and China Power Investment Corporation for the implementation of seven large dams along Irrawaddy, Mali, and N'Mai rivers in Kachin state for a total of more than 17,000 MW. However, the implementation of these projects has met resistance. The largest of the proposed projects in this cluster, the 6,000 MW Myitsone dam, has been suspended since 2011 by order of the Government of Myanmar as a result of mounting pressure from local population and for environmental impact concerns (ADB, 2013).

Results of Power Benefit Assessment

Using the intended distribution of power to the different countries, two sets of values were calculated. One is the annual power production intended for use in each country. The other is the annual power export from the host country to other countries. Table 8.5 presents the results from the annual power supply benefits assessment.

Table 8.5: Results of Power Supply Benefit Assessment

POWER SUPPLY (GWh)					
SCENARIO (year)	**LAO PDR**	**THAILAND**	**CAMBODIA**	**VIET NAM**	**TOTAL**
2015	4,265	10,205	207	12,314	26,991
2030	15,025	55,474	10,120	30,279	110,898
BENEFIT FROM POWER SUPPLY (Million $)					
SCENARIO	**LAO PDR**	**THAILAND**	**CAMBODIA**	**VIET NAM**	**TOTAL**
2015	5,026	10,423	253	7,515	23,217
2030	11,532	34,150	6,471	13,141	65,293

Note: GWh = gigawatt-hour

When the part of the project production is destined for another country, the gross annual export benefit is calculated at a proxy value for the actual trade price. This proxy is obtained as a discount over the replacement cost of power at the importing country and the discount is an input in page “SUMMARY” of the PEM Model. The result presented in Table 8.6 is only applicable to the host country.

Table 8.6: Results of Power Export Benefit Assessment

POWER EXPORT (GWh)					
SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	11,321	-	-	-	11,321
2030	64,792	-	9,528	-	74,320
BENEFIT FROM POWER EXPORT (in US$ million)					
SCENARIO	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	9,449	-	-	-	9,449
2030	31,816	-	2,585	-	34,401

The net annual economic benefit of the project is calculated differently for the host country and for the importing countries. For the host country, the net annual benefit is the sum of the benefit from power supply and from export less the annual cost of the project. For importing countries, the net annual benefit is the difference between the replacement value of imported power and the cost of import calculated at the proxy trade price. Table 8.7 presents the results.

Table 8.7: Results of Net Annual Economic Benefit Assessment

INVESTMENT (in US$ million)					
SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	2,933	-	102	3,227	6,262
2030	11,668	-	8,112	3,302	23,081
ECONOMIC BENEFIT (in US$ million)					
SCENARIO	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	11,302	1,563	122	3,467	16,454
2030	30,740	5,122	212	4,357	40,431

Table 8.8: Summary of Results

SCENARIO (year)	POWER SUPPLY (GWh)	POWER EXPORT (GWh)	CAPITAL INVESTMENT ($ million)	NET BENEFIT ($ million)	DISTRIBUTION OF NET BENEFITS (%)			
					LAO PDR	THAI	CAM	VN
2015	26,991	11,321	6,262	16,454	69	10	1	21
2030	110,898	74,320	23,081	40,431	76	13	1	11

Table 8.9: Summary of CO_2 Emission Reduction from Thermal Power Replacement

Estimated level of CO_2 emission from different types of thermal power pant						
Type of Thermal Plant	Estimation of emission (CO_2 tonnes/MWh)	Lao PDR	Thailand	Cambodia	Viet Nam
		0.84	0.71	0.84	0.92
Coal-fired steam plant	0.920	50%	60%	50%	100%
Oil-fired steam plant	0.755	50%	0%	50%	0%
Gas-fired combined cycle	0.404	0%	40%	0%	0%

Reduction of CO_2 Emissions (thermal power plant replacement by hydropower)

- LMB projects in operation by 2015: 22.36 million tons/year
- LMB projects in operation by 2030: 88.50 million tons/year

CO_2 Emissions from Hydropower Reservoirs

- LMB projects in operation by 2015: 1.49 million tons/year
- LMB projects in operation by 2030: 6.05 million tons/year

Net CO_2 Emissions Reduction from Hydropower Development

- LMB projects in operation by 2015: 20.87 million tons/year
- LMB projects in operation by 2030: 82.45 million tons/year

Key Challenges and Lessons Learned

- Political issues and unrest, including territorial disputes; and ensuring the ongoing cooperation, cost sharing, and coordinated decision making in the operation of regional market.
- Coordination issue, including conflicts between national and regional energy investment strategies.
- Investment issues, including the enormous financing requirements for expanding cooperation, such as developing generation assets, regional transmission network, institutional and policy frameworks, and the high risk perception by potential investors and developers (particularly in GMS members whose legal and political systems make protection of investment less certain) and the inability of the public sector to support these investments.

- Technical challenges of interconnecting disparate power system and ensuring security including communications, metering, and allocation of responsibility throughout a regional grid.
- Valuation issues arising from undeveloped power market in GMS members creating uncertainty in the determination of energy cost, tariffs, and price.
- Social issues, such as opposition to large hydropower projects and disputes over whether the regionalization of the GMS energy sector will actually enhance sustainable development or reduce poverty in light of concern that the benefit might be captured by a select group within certain GMS members.
- The Lao PDR hydropower industry's successful experience can be applied regionally in raising financing and attracting strong and credit-worthy off-takers. EGAT paved the way for the eventual structuring of a domestic supply project in the Lao PDR. Even today, only EGAT projects are able to move forward on a pure, project-financed basis with commercial lenders, as a result of the time-tested reputation of EGAT in its cross-border power ventures.
- In the case of Myanmar, a similar model is possible as its power exporting industry is at the same stage as that which the Lao PDR began building 20 years ago.
- The key role played by IFIs in fostering the necessary legal and legislative framework for commercial lenders to enter into an emerging economy's energy export market is worth looking into. The involvement of IFIs contributed to improving the financial and legal systems, political risk guarantee, and to providing the lender with enough assurance to feel comfortable in placing a financial stake in hydropower investment.

Conclusion

From the research, it is clear that power trade through power grid interconnection in GMS countries will result in significant benefits for individual countries and for the region. Among the benefits are as follows:

- Reduce dependency in national investment and provide alternative capital to invest in the power reserves to meet peak demand.

- Provide more reliable and alternative supply of electricity from interconnection network in case of power failure or shortage.
- Reduce operation costs and greenhouse gas emissions and other pollutants.
- Provide more economical source of energy, contributing to improved ability to access electricity.
- Contribute to national budget and economy with more tax revenues from the sale of electricity and from wheeling charge a (i.e., use of transmission charges).

However, hydropower could play an increasingly important role in the EMI of the GMS in the near future, serving as the answer to the rapidly growing demand for energy in the GMS countries while providing an alternative to dependency on fossil fuel. Considering the magnitude of the hydropower generating potential of the Mekong region, significant revenue benefits can be expected from electricity export.

Today, the existing power interconnections in GMS serve either to transmit electricity generated from export-oriented power plants or to dispatch power to cross-border areas experiencing domestic supply deficiencies and to areas distant from national networks.

Significant progress has been made in the GMS regional power trade since the beginning of GMS regional energy cooperation through a two-pronged approach to develop the GMS power market —the policy and institutional frameworks for promoting power trade and physical interconnections to facilitate cross-border power. However, to move toward a GMS power market, more efforts should be made by the GMS members themselves to realize the full benefits of synchronous operations in the GMS.

Recommendations

- For better assessment of hydropower generation potential, the main mechanism for power exchange in the GMS will be based on large-scale hydropower generation export. To attract more investors and reduce risk in hydropower investments, there is a need to refine investment cost, acquire hydrological data, and mitigate social and environmental impacts of these hydropower export projects to make them more sustainable.

- Promote inter-government joint investments in hydropower development and in power trading, and enhance the participation of the private sector and IFIs to accelerate the pace of development toward EMI.
- GMS members need to provide support to the Regional Power Trade Coordination Center's activities and role to reach a clear basis for regional market rules. These rules should comprise agreed rules and agreed indicative plans for interconnection (regional master integration planning) for a more functional regional market with genuine exchange of electricity, leading to greater supply reliability, improved quality of power supply, and lower costs. The Regional Master Plan needs to be reviewed and adapted regularly.
- A consistent update of the Power Development Plan and Transmission Expansion Plan among the GMS individual countries is needed to fit them into the regional master plan or to make the regional master plan regularly adapted.
- The GMS members need to support the Regional Investment Framework (RIF) of the energy sector and to prepare for its implementation.

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Annex-1
Methodology

Conceptual Aspects for Replacement Cost of Power Calculation

The economic evaluation of hydropower projects involves the calculation of the least cost of power generation that would be an alternative to hydropower. The least-cost alternative is a thermal plant using fossil fuel because, in general terms, including equivalent power reliability considerations, all other generation technologies for renewable resources are more expensive than hydropower generation. There are many thermal generation technologies in use today and the choice depends on the availability and price of fuels and the scale of the power systems to be supplied.

Expected Generation Expansion

The power generation structure of the Lao PDR will not change and will continue to be predominately hydropower. The only reason for the Lao PDR to use any other generation technology but hydropower is the cost of expanding and maintaining the transmission grid to reach every load.

Thailand will move toward reducing its dependency on gas and coal with as much hydropower as it can competitively import. Natural gas is a fuel that can be used advantageously in several sectors including industrial heat, residential cooking, and transport and, therefore, its use for power generation may not be the most efficient from an overall national energy planning perspective.

Cambodia's power sector is expected to change radically from its current, almost complete, oil dependency to a mix of hydropower and coal.

Viet Nam has ambitious plans for new coal and nuclear capacity by 2020 but that capacity and the expected capacity of new domestic hydropower still leaves a large gap against expected demand. That gap will likely be filled by imports of hydropower energy from the Lao PDR, more aggressive coal or nuclear development, or more likely, a combination of all these three.

The energy supply sources for Yunnan and Guangxi provinces of China are mainly hydropower dominated but mixed with coal. The future expansion will remain unchanged due to the huge potential of hydropower and coal resources in Yunnan with some plans to initiate nuclear generation in Guangxi.

Myanmar's energy supply relied heavily on seasonal hydropower generation, followed by gas, with a few portion of coal, but lacks domestic gas supply and capacity for gas-fired power generation to maintain the stability of the supply system. For the future, generation expansion plans will mainly focus on hydropower and gas-fired power generation, with some options for coal-fired power generation.

Viable Thermal Alternatives

Thermal generation alternatives are a combination of fuel and generation technology. Not all the technologies can burn all fuel and, generally, the most expensive technologies to build can burn cheaper fuel and vice versa.

Coal is the cheapest fossil fuel but can only be burned in steam plants, which are expensive to build.

Natural gas can also be burned in steam plants but it is cheaper and more efficient to use in a technology called "combined cycle" that consist of a combination turbine (similar to jet engine used in aircraft) and steam turbines. Steam turbine and combined cycle technologies are capable of large- scale generation with capacities of up to several thousand megawatts (MW) per plant.

Two oil products are of common use in smaller-scale power generation. **Distillate fuel oil**, also known as "diesel oil", is very expensive compared to natural gas or coal but can be used in low-cost diesel engines that are only practical with a capacity of just a fraction of one MW. These engines are relatively light machines, similar to diesel engines used in trucks and are known as "high-speed diesel". **Residual oil**, also known as "bunker oil", has a lower cost compared to that of crude oil and can be used in heavier diesel engines with capacity of up to 30 MW. These engines are also used in ships

and are known as “low-speed diesel”. The cost is comparable to that of combined cycle machines.
Nuclear power is, of course, a viable technology for the scale of the system of Thailand and Viet Nam but its use as thermal reference for hydroelectric project evaluation is not practical because the full extent of nuclear generation cost, including fuel disposal and plant decommissioning, is very complex to evaluate.

In summary, in the absence of hydropower and nuclear power, a large system would lean toward combined cycle technology if natural gas and steam technology were available, using domestic or imported coal if gas is not available. A small system would start with high-speed diesel for very small isolated loads, moving to low-speed diesel as more loads become interconnected and, finally, would start moving into combined cycle or steam turbine technologies depending on the availability of natural gas.

Fuel Costs

Fuel prices have been volatile in the past few years and this volatility complicates the use of any specific value. Current price for oil products can be derived by using the cost of crude for bunker and approximately 50% above the cost of crude for diesel. Current cost of natural gas prices can be estimated based on recent transactions in Viet Nam and Thailand.

However, energy observers agree that it is highly probable that fuel prices, will, over the foreseeable future, increase at a higher rate than the general inflation that is expected. This increase in price above the general level of inflation is called escalation. In particular, fuels that are of practical use in the transportation sector, such as oil or natural gas, are likely to experience the highest price escalation. For this reason, current prices are not appropriate to be used in an analysis based on real terms since they could not be converted into nominal prices by merely applying inflation.

The value used for current fuel prices and for the assumed fuel price escalation are variable in the “SUMMARY” page of the Power Evaluation Model, PEM. These values and the resulting “levelised” fuel prices are shown in Table 8.A1.

Table 8.A1: Current and "Levelised" Fuel Prices

Fuel Type	Diesel	Natural Gas	Bunker	Coal
Fuel Price Trade Unit	**US$/bbl**	**US$/TCM**	**US$/bbl**	**US$/ton**
Reference heat content per trade unit in Mbtu	5.54	36.27	5.81	22.00
2010 fuel price in US$/Mbtu	22.60	14.00	12.00	4.00
2010 fuel price in US$/trade unit	125.1	507.8	69.8	88.0
Mean annual escalation rate of fuel prices (Sensitivity)	0%	0%	0%	0%
Current fuel price "levelised" value	**125.0**	**507.8**	**69.8**	**88.0**

Notes:

Bbl = American barrel = 42 American gallons = 158.97 liters
TCM = thousand cubics metres = 35,314.7 cubic feet
Ton = metric ton = 1,000 kilograms = 2,204.6 pounds
Mbtu = million British thermal units = 251,996 kilocalories

Source: Power Evaluation Model, 2013

To account for the real future cost of replacement power, the current price had been escalated over the next 20 years, at the expected rate of increase in price over general inflation. The resulting annual prices are then "levelised" for the 20-year period using the economic discount rate. The "levelised" value is such that the present 2010 value of a string of constant annual "levelised" values is the same as the present value of the specific annual escalated values.

Variable Cost of Replacement Power

The cost of fuel is the primary component of the variable cost of power from thermal plant. This component is obtained by combining the cost of the fuel with assumption on the heat content of each fuel and the thermal efficiency or "heat rate" of each generation technology. Other components of the variable cost are then added as a percent of the fuel cost to account for lubricants and other consumables. The calculation of variable cost for the four alternatives considered is shown in Table 8.A2. The variable cost is also known as the "Energy" cost of power. "Power" is a term that, in the electricity generation industry, includes both energy and capacity components.

Table 8.A2: Variable Cost of Replacement Power

Fuel type		Distillate Oil No. 2	Natural Gas	Residual Oil No. 6	Anthracite Coal
Usual trade unit	Unit	Barrel	Thousand Cubic Metres	Barrel	Metric Ton
Heat content per trade unit	Mbtu/unit	5.54	36.27	5.81	22.00
Cost per trade unit	US$/unit	125.00	507.76	70.00	88.00
Unit fuel cost	US$/Mbtu	22.58	14.00	12.04	4.00
Heat rate	btu/kwh	12,000	6,800	8,500	9,125
Variable cost fuel	US$/MWh	270.97	95.20	102.36	36.50
Variable operation and maintenance	% of fuel cost	5.50%	10.50%	9.80%	8.22%
Variable operation and maintenance	US$/MWh	14.90	10.00	10.03	3.00
Total variable cost	US$/MWh	285.88	105.20	112.39	39.50

Source: Power Evaluation Model 2013

Investment: The sum of the engineering, procurement, and construction (EPC) and the interest during construction (IDC) results in the present value of the investment at the time of commissioning the project.

Fixed Cost of Replacement Power: This is the fixed cost of power in the plant’s annual cost of operating expense and the cost of amortizing the investment on the plant.

Unit Annual Fixed Cost: This is the sum of the annual capital and operating cost divided by the installed capacity of the plant. Table 8.A3 shows the calculation of unit fixed costs for the generation alternatives under consideration.

Table 8.A3: Calculation Unit Fixed Cost of Replacement Power

Reference Generation Technology	Unit	High-Speed Diesel	Combined Cycle	Low-Speed Diesel	Coal Fired Steam Turbine
Fixed cost calculation					
Unit EPC	US$/kW	400	800	1,000	1,600
Construction period	Years	1	2	2	5
Unit IDC	US$/kW	20	80	100	400
Unit capital cost	US$/kW	420	880	1,100	2,000
Economic life	Years	15	25	15	30
Capital recovery factor		0.131	0.11	0.131	0.106
Unit annual capital cost	US$/kW	55.22	96.95	144.62	212.16
Fixed operation and maintenance cost	% of EPC per year	3.00%	3.00%	3.00%	3.00%
Unit fixed operation and maintenance cost	US$/kW	12	24	30	48
Unit annual fixed cost	US$/kW	67.22	120.95	174.62	260.16

EPC = engineering, procurement, and construction, IDC = interest during construction, K= kilowatt
Data source: Power Evaluation Model Result, 2013

Capital Costs

Unit EPC Cost: This is the estimated cost of engineering procurement and construction involved in building the plant. The Unit EPC is obtained by dividing the EPC cost by the installed capacity of the plant.

IDC Cost: The interest during construction represents the opportunity cost of capital disbursed during construction up to the time when the project starts operating. This cost is a function of the duration of construction, of the discount rate, and also of the schedule of disbursement during construction. To simplify the analysis, it is assumed that IDC can be approximated by using the following formula:

$$IDC = 0.5 * EPC * P * i$$

Where:

IDC = is the interest rate during construction
EPC = is the EPC in million US$
i = is the discount rate
P = is the construction period in years

Annual Capital Costs

The annual amortization of the investment over its economic life *L* is a value, such that the accumulated present value of the string of *L* constant values is equal to the investment. This annual amortization is obtained by multiplying the investment by the Capital Recovery Factor (CRF). The CRF is given by the following formula:

$$CRF = [(1+i)^L * i] / [(1+i)^L - 1]$$

Where:
CRF = Capital Recovery Factor
i = discount rate
L = economic life in years

Then [**Annual Capital Cost = Investment * CRF]**

The annual capital cost is an economic and cost accounting concept that does not represent a real annual disbursement. However, the CRF can also be used to calculate the annual cost of debt services on a loan used to finance the plant. This can be done by making the following replacement:

a) Replace “investment” by “Loan Amount”
b) Replace “Economic life” by “Loan Term”
c) Replace “Discount Rate” by “Loan Interest”

Monomic Cost of Replacement Power

Generation projects contribute two types of services to an electric power system. One service is “energy supply” and the value of this service is captured by the variable cost of replacement power discussed above and commonly measured in $/MWh. The other service is “Capacity Supply”, which represents the contribution to the system’s ability to meet peak demand. The value of this service is captured by the fixed cost of replacement power discussed above and commonly measured in $/MW-year. It is often more practical in economic analysis to use a single value that captures both energy and capacity component of value. This is called the "monomic (or one-part) value" and it is obtained through the following formula:

$$M = [(E*8760*LF) + C]/(8760*LF)$$

Where:

M = Monomic value
E = Energy value
LF = Load factor
8760 = number of hours per year

This formula essentially spreads the fixed cost of one megawatt of capacity (required to meet peak demand) over the expected megawatt-hours of energy demand that are expected to be associated with that during one year.

Such association of energy of capacity is captured by the "Load Factor" and is typically between 0.60 and 0.80 for most power systems. The value 0.70 was used in this approximation. Table 8.A4 shows the calculation of monomic value of the alternative under consideration for a range of load factor of the power system under analysis.

Table 8.A4: Monomic Replacement Cost of Power

Capacity Value	**US$/kW-year**	**67.22**	**120.95**	**174.62**	**260.16**
Energy Value	**US$/MWh**	**285.88**	**105.2**	**112.39**	**39.5**
	Load Factor (%)				
Monomic value in US$/MWh as a function of capacity factor	10	362.6	243.3	311.7	336.5
	20	324.2	174.2	212.1	188
	30	311.5	151.2	178.8	138.5
	40	305.1	139.7	162.2	113.7
	50	301.2	132.8	152.3	98.9
	60	298.7	128.2	145.6	89
	70	**296.8**	**124.9**	**140.9**	**81.9**
	80	295.5	122.5	137.3	76.6

Source: Power Evaluation Model, 2013

Replacement Cost by Country

Once the monomic cost of power for each thermal generation option has been determined, there is a need to estimate what will be the proportion of each option that would be used in each country if hydropower were not available. Some clues can be obtained from the expected generation expansion plans. This will be explained below as the results are shown in Table 8.A5.

Table 8.A5: Power Replacement Cost, by Country

Generation Technology	Cost	Percentage Use of Generation Technology (%)			
	US$/MWh	LAO PDR	THAILAND	CAMBODIA	VIET NAM
High- or medium-speed diesel units using diesel oil	**296.8**	**30**	**9**	**30**	**0**
Low-speed diesel units using bunker oil	**140.9**	**20**	**1.0**	**30**	**0**
Combined cycle units using natural gas	**124.9**	**0**	**82**	**0**	**0**
Steam turbine units using coal	**81.9**	**50**	**8**	**40**	**100.0**
Monomic replacement cost of power (US$/MWh) at 70% system load factor		158.2	137.1	164.1	81.9

Source: Power Evaluation Model, 2013

The clearest case is Viet Nam. It seems reasonable to expect that, if nuclear or hydropower were not viable options, then Viet Nam would pursue a fully coal-fired power generation expansion and the replacement cost of that power, accounting for all costs including escalation of coal prices, is US$**81.9/MWh (or 8.2 cents/kWh)**.

Thailand is a little more complex because it is unclear how much of future demand can actually be covered by natural gas, which probably would be the preferred option since it is both cleaner and cheaper power. It has been assumed that in the absence of hydropower, 82% of the incremental demand would be covered by combined cycle machines using natural gas and the rest with coal-fired stream plants and oil-fired stream plants. This will result in a replacement cost of power of US$**137.1/MWh (or 13.7 cents/kWh)**.

Cambodia currently relies almost entirely on oil-fired power generation and reports a plan for coal-fired power generation. Coal would, therefore, appear like a reasonable alternative but its current reliance on small diesel generators makes it unlikely that the transmission system would be capable of immediately providing coal-fired power everywhere. Thus, a balanced mix of coal-fired system and high-speed diesel has been assumed as a reasonable option over the next 20 years if hydropower was not available. This will result in a replacement cost of power of US$**164.1/MWh (or 16.4 cents/kWh)**.

The Lao PDR is the most difficult case to assess since there are no plans or expectations for thermal power supply. However, the country has a reasonable transmission and, thus, it could be expected that, in the absence of hydro, much of the load could be supplied with coal-fired power generation or at least, low-speed diesel generator and only isolated parts would still rely on high-speed diesel. A reasonable combination of these thermal generation options would result in a replacement cost of power of US$**158.2/MWh (or 15.8 cents/kWh)**.

METHODOLOGY FOR CO_2 EMISSION REDUCTION CALCULATION

Hydropower projects will avoid the emission of carbon dioxide (CO_2) that would result from fossil fuel-fired power generation. In addition, the project would also mitigate other pollutants, such as sulphur oxide (SO_2), nitrate oxide (NO_x), and particulates associated with power generation from fossil fuels. Thus, the hydropower project will contribute to the reduction of CO_2 emission from existing and future thermal power plants using diesel generator, coal, and natural gas. The amount of reduction of CO_2 by the hydropower (Y) can be calculated using the following formula;

Y = CO_2 emission from thermal power plants – CO_2 emission by hydropower projects + disappearance of CO_2 absorption resulting from deforestation + CO_2 emission from reservoir

Since hydropower is a clean energy source, there will be no CO_2 emissions that are directly related to hydropower generation.

CO_2 Emissions from the Thermal Power Plant

CO_2 from diesel generator per kWh is calculated with the following formula (Nippon Koei Co. Ltd., 2007).

$$Z = \frac{Eh \times SFCh \times RDh \times EFh \times HVh + Ed \times SFCd \times RDd \times EFd \times HVd}{Eh + Ed}$$

Where:

Z = emission from diesel generator per kWh generation

h = heavy fuel oil or heavy fuel oil-fired generating units

d = light diesel oil or light diesel oil-fired generating units

E = energy production (LDO-fired diesel unit: 219.8 GWh/year, HFO-fired diesel unit: 587.3 GWh/year)

Source: Electricité du Cambodge (2005), *Statistical Handbook, 2005, by Cambodian State Own Power Utility Company (EDC),* Phnom Penh, Cambodia

RD = relative density (LDO = 0.876, HFO = 0.900)

SFC = specific fuel consumption (LDO-fired diesel unit: 0.285 liter/kWh, HFO-fired diesel unit: 0.233 liter/kWh

Source: Electricité du Cambodge (2005), *Statistical Handbook, 2005, by Cambodian State Own Power Utility Company (EDC),* Phnom Penh, Cambodia

EF = emission factor (LDO = 0.0741 kg-CO_2/GJ, HFO = 0.0770 kg-CO_2/GJ)

Source: CDM Executive Board, June 2006.

HV: heat value of fuel (LDO = 48.61 GJ/ton, HFO = 43.39 GJ/ton)

Source: US Department Of Energy (DOE) /Energy Information Administrative (EIA) (2005), *Annual Energy Outlook, 2005*, USA.

As a result, it was estimated that CO_2 emission from diesel generator is **0.755 ton/MWh**

From the International Energy Agency (IEA) (2012), the CO_2 emission from coal power plant is **0.920 ton/MWh.**

The CO_2 emission from combined cycle gas turbine (CCGT) using natural gas is **0.404 ton/MWh**

As result from the CO_2 emission reduction due to the replacement of thermal power plant by hydropower development in the Lower Mekong River Basin the following scenario is presented:

Emission Reduction of CO_2 in Million Tons/Year

SCENARIO (year)	LAO PDR	THAILAND	CAMBODIA	VIET NAM	TOTAL
2015	3.57	4.90	0.17	11.33	**19.97**
2030	12.58	26.65	8.31	27.86	**75.40**

Source: MRC (2014)

Disappearance of CO_2 Absorption by Deforestation

The hydropower project included the construction of dam to create a head for power generation and to control the flow of water and, therefore, certain areas of the land will be submerged under the reservoir. Thus, after the implementation, certain areas of forest land will be submerged. In this analysis, the tropical forest's annual absorption of CO_2 was estimated based on the following formula and data quoted from the IPCC guidelines for National Green House Gas inventories in 2006.

$$\text{Annual } CO_2 \text{ Absorption (ton-}CO_2\text{/ha)} = (AGBG \times (1+R) \times CF \times MW_{CO2})/MW_c$$

Where:

AGBG: Above ground biomass growth (2.2 ton dry matter (dm.)/ha/year, tropical rain forest in Asia continent)
R: Ratio of below-ground biomass (0.37 ton rood dry matter (d.m.)/ton shoot dry matter (d.m.), tropical rainforest)
CF: Carbon fraction (0.47 ton-C/ton d.m., tropical and subtropical, all parts of a tree)
MW: Molecular weight (CO_2 = 44, C = 12)

Annual CO_2 absorption of tropical forest in Mekong was estimated at 5.19 ton-CO_2/ha/year.

Due to unavailability of data for forest areas submerged by reservoir impoundment of hydropower projects, the CO_2 absorption of forest was neglected in the net CO_2 emission calculation.

CO_2 Emission from the Reservoirs

CO_2 emission from reservoir results from the decomposition of leaves, twigs, and other rapidly degradable biomass. Slowly decaying woody biomass, organic matters washed into the reservoir from upstream, and the growth of biomass in the reservoir provide long-term source of CO_2 and methane production. Reservoir emission lasts for many decades at least and presumable for the life of the reservoir. According to the "thresholds and criteria for the eligibility of hydroelectricity power plant with reservoirs as CDM projects activities" of the Clean Development Mechanism Executive Board, the emission of CO_2 from the reservoir is defined as follows, based on threshold in terms of power density (installed power generation capacity divided by the flooded surface area Watt per square meter (W/m^2); (UNFCCC-2006); (CDM-EB23, Report Annex 5):

i. Hydropower plant with power densities less than or equal to 4 W/m^2 cannot use current methodologies.
ii. Hydropower plant with power densities greater than 4 W/m^2 but less than or equal to 10 W/m^2 can use current approved methodologies with emission factor of 90 g-CO_2/kWh for project reservoir emission.
iii. Hydropower plant with power densities greater than 10 W/m^2 can use current approved methodologies and the project emission from reservoir may be neglected.

With reference to these criteria, CO_2 emission from a reservoir was calculated at 90 g-CO_2/kWh with a power density less than 10 W/m^2 and zero with power density greater than 10 W/m^2.

Below is the amount of CO_2 emission from hydropower reservoirs in the Lower Mekong River Basin and net calculation of CO_2 emission reduction from hydropower development.

SCENARIO (year)	CO_2 Emission from Hydropower Reservoirs	Net CO_2 Emission Reduction from Hydropower Development
2015	1.49 (million ton/year of CO_2)	18.48 (million ton/year of CO_2)
2030	6.05 (million ton/year of CO_2)	69.35 (million ton/year of CO_2)