Discussion Document

Comments on Indicative Master Plan on Power Interconnection in GMS Countries

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Introduction

The *Indicative Master Plan on Power Interconnection in GMS Countries* proposes extended power cooperation development of the electric power systems of the countries of the Greater Mekong Sub-region. The Plan anticipates savings of (net present value in 2001 using a 12% discount rate) US$914 M for extended power cooperation as compared with the study alternative of limited cooperation.

While the technical analysis in the report generally appears to be thorough within the terms of reference for the study, there are some points that should be reviewed before concluding that the recommended scenario is truly economic and feasible compared with the limited cooperation alternative.

These points of concern can be divided into: the source of anticipated financial benefits, completeness of the cost estimates, and regulatory and technical coordination requirements.

Brief Overview of Indicative Master Plan

The *Indicative Master Plan on Power Interconnection in GMS Countries* presents the results of long-term planning studies of the electric power needs of the Greater Mekong Sub-region countries (Thailand, Viet Nam, Cambodia, Lao PDR, and to a lesser extent Myanmar and China's Yunnan province). The studies are based on pre-existing plans for generation development in the region.

The Plan contains forecasts for energy and peak demand requirements out to 2020. Regional energy consumption and peak demand are predicted to grow from 2005 to 2010 at an average annual rate of nearly 7%.

The Plan compares capital and operating costs for two scenarios: Scenario 1, a Limited Power Cooperation scenario with only limited interconnection between neighbouring systems, and Scenario 2, an Extended Power Cooperation scenario with relatively extensive interconnection between neighbouring systems. Scenario 2 is further subdivided into alternative sub-scenarios based on varying amounts of power generation and transmission grid development. The full set of scenarios is described in Table 1.

The power that is imported in Scenario 2 has been replaced in Scenario 1 with alternative thermal generation. In Thailand the alternative generation is mostly coal to obtain fuel diversity, driven by concerns over increasing the already high proportion of gas-fired generation. In Viet Nam the alternative generation is a combination of coal and gas.

Generation costs for the economic comparison include investment, maintenance, fuel and spinning reserve costs. Generation costs have been reduced by the residual asset value in 2020 (the end of the study period), and for the Extended Cooperation scenarios the generation costs are reduced by an amount equal to the estimated value of the increased reliability due to interconnection.

Scenario	*Description*
1 (Limited Cooperation)	Only existing and committed interconnections.
2A (Extended cooperation, full generation)	Cooperative generation development and interconnection based mainly on existing MOUs.
2B (Extended cooperation, economic generation)	As for 2A except most expensive generation export projects in Cambodia and Lao PDR are dropped.
2C (Extended cooperation, economic generation without Tasang)	As for 2B but without Tasang hydro project in Myanmar.
2A-rg (Extended cooperation, full generation, reduced grid)	As for 2A but with reduced transmission grid in Lao PDR.
2B-rg (Extended cooperation, economic generation, reduced grid)	As for 2B but with reduced transmission grid in Lao PDR.
2C-rg (Extended cooperation, economic generation without Tasang, reduced grid)	As for 2C but with reduced transmission grid in Lao PDR.

Table 1: Scenarios from Indicative Master Plan

For transmission costs, the Plan does not attempt to identify all costs, and specifically excludes the costs of reinforcing national transmission grids where the reinforcement is independent of interconnection. Only differences in transmission requirements and costs are considered for comparison of the scenarios. The Plan focuses on differences in investment requirements, timing, transmission losses, and operation and maintenance costs.

The results of the economic comparison are shown in Table 2.

	Limited Cooperation	*Extended Power Cooperation*					
	Scenario 1	*Scenario 2A*	*Scenario 2B*	*Scenario 2C*	*Scenario 2A-rg*	*Scenario 2B-rg*	*Scenario 2C-rg*
Generation System	$44.354	$42.457	$42.283	$42.755	$42.440	$42.278	$42.750
Transmission System	$0.056	$1.499	$1.213	$1.010	$1.453	$1.221	$1.019
Total Costs	$44.410	$43.956	$43.496	$43.765	$43.893	$43.499	$43.769
Cost Savings over Scenario 1		$0.454	$0.914	$0.645	$0.517	$0.911	$0.641

Table 2: Economic comparison of alternative scenarios 2005-2020 (12% discount rate, discounted to 2001, values in US$ Billion). (From Table 6-16 in the Plan.)

Sensitivity analysis performed as part of the studies showed that, while the magnitudes of the benefits vary, benefits still exist for discount rates of 10% to 14%. Sensitivity analysis was also used to show that the economic benefits are “fairly robust against” increase in fuel costs (50% higher gas price, 25% higher coal price in 2020). To examine the impact of uncertainties in selected costs, the maximum increase was determined for four cost elements at 12% discount rate. These values are shown in Table 3.

The Plan also estimates values for GHG reduction, but these values do not factor into the estimated savings due to the high uncertainty in the estimated values.

Cost component	*Maximum Increase*		
	Scenario 2A	*Scenario 2B*	*Scenario 2C*
Investment cost for export hydro projects	+14%	+33%	+31%
Investment cost for Tasang hydro power project (excluding transmission)	+44%	+89%	–
Transmission investment costs	+30%	+75%	+63%
Coal price in Yunnan Province	+209%	+419%	+290%

Table 3: Increase in selected cost factors to eliminate economic benefit of Extended Cooperation scenarios compared with Limited Cooperation Scenario. (Discount rate 12%. From Table 6-21 in the Plan.)

The Plan's recommended scenario is Extended Cooperation Scenario 2B, which produces the greatest expected cost savings over Limited Cooperation Scenario 1.

Source of Financial Benefits

Power System interconnections commonly provide many types of benefit, including increased reliability, capacity sharing, sharing of operating reserve, and the potential for economic energy exchange. For the GMS Indicative Master Plan the primary financial benefits of interconnection appear to come from the substitution of hydro generation for thermal generation.

In scenarios 2A and 2B the majority of saving in generation cost (78% and 64%, respectively) is due to reduced fuel and variable operations & maintenance (O&M) costs.[1] For Scenario 2A there is a reduction in installed generation capacity (by 2020) of approximately 1080 MW[2], but the associated cost saving is fully offset by the higher investment cost of hydropower compared with the thermal alternatives. There are, however, minor savings due to the associated reduction of fixed O&M costs, amounting to approximately 11% of the total savings in generation costs for this scenario. For scenarios 2B and 2C there are savings in both generation investment and fixed O&M costs, so that total generation savings due to reduced generation capacity costs (investment less residual value plus fixed O&M costs) amount to approximately 27% and 50%, respectively, of the total savings in generation costs for these scenarios.

Using data from tables 6-12 through 6-16 from the Final Report it is possible to construct Table 4 following, showing the breakdown of total scenario costs into "Transmission Costs", "Fuel and Variable O&M Generation Costs" and "Other Generation Costs". From Table 4 it is obvious that the higher transmission costs associated with interconnection more than compensate for any savings due to generation capacity reduction or other interconnection benefits other than economic energy exchange. The residual savings are, for each of the three scenarios, due to the lower operating (fuel and variable O&M) costs associated with substitution of hydro generation for thermal generation.

[1] See page 6-16 and tables 6-13 and 6-14 in Chapter 6 of Volume III-A of the Final Report.

[2] This reduction results from a sharing of installed capacity made possible by a difference between Thailand and the other GMS countries in the hour of peak load.

	Estimated Costs				Estimated Cost Savings		
	Scenario				Scenario		
	1	2A	2B	2C	2A	2B	2C
Transmission Costs	$0.056	$1.499	$1.213	$1.010	($1.443)	($1.157)	($0.954)
Other Generation Costs	$16.397	$15.986	$15.656	$15.480	$0.411	$0.741	$0.917
Fuel and Variable O&M Generation Costs	$27.957	$26.471	$26.627	$27.275	$1.486	$1.330	$0.682
Total	**$44.410**	**$43.956**	**$43.496**	**$43.765**	**$0.454**	**$0.914**	**$0.645**

Table 4: Breakdown of total scenario costs into "Transmission Costs", "Fuel and Variable O&M Generation Costs" and "Other Generation Costs". (Data from Tables 6-12 through 6-16 from the Indicative Master Plan Final Report. Values are NPV 2001 with 12% discount rate, in US$ Billion.)

Even after including the fuel and variable O&M generation cost reductions, the estimated savings are relatively small on a percentage basis. Compared with the total (NPV 2001) cost for each scenario, the percentage benefits range from 1.0% for Scenario 2A to 2.1% for Scenario 2B. This leaves little room for error. As pointed out by the consultants[3], "... although the differences between the scenarios are considerable in absolute terms, they are in [sic] the order of magnitude of 1-2% in relative terms. Thus even if existing tariffs to final consumers were cost-based today (which they are not), the selection of scenario would not have major impacts on average GMS consumer tariffs for electricity."

Even if the total risk were limited to the additional transmission costs (which it is not[4]), the potential (NPV 2001) benefits over the entire study period are only 30% to 75% (for scenarios 2A and 2B, respectively) as a percentage of the funds at risk.

Completeness of Cost Estimates

The Plan's economic analysis includes the construction- and operation-related costs that would be expected in a plan for system expansion. It does not include the costs required to transition the GMS nations from loosely connected independent systems (with very limited grids in some cases, such as Cambodia) into a highly interdependent operating structure capable of constructing, maintaining and operating a rapidly growing power system.

Included Costs

The Plan's economic analysis includes:

- Generation investment costs, including interest during construction (IDC) and allowing for residual asset values at the end of the study period. These cost estimates apparently were obtained from other sources (e.g. EGAT, other reports, etc.).

[3] The last paragraph on page 38 of the Executive Summary (Volume 1) of the Final Report.

[4] See following for a discussion of additional items not included in the Plan costs. In addition, there are significant opportunity costs to the GMS nations if the interconnection encounters other, non-financial (e.g. operating, political) difficulties that reduce the reliability of supply or, due to extra-national events, delay availability of import energy so as to create an energy shortfall in Thailand or Viet Nam.

- Hydropower and thermal plant operation and maintenance costs, including fuel costs. Annual O&M costs for hydropower plants were estimated as 1.5% of the investment cost.
- Transmission system investments, including transmission lines and substations. Costs are stated to include "the total costs for transmission components installed and ready for operation", but excluding taxes, duties and IDC. Substation costs include civil works, transformers, circuit breakers, shunt capacitors, AC/DC supply, metering, communications, remote control, bus-bar protection (500 kV substations), land acquisition, and engineering and construction costs. Costs for line series compensation, where used, were estimated separately based on information obtained from ABB.
- Transmission operation and maintenance costs, estimated as 1.5% of the investment.
- Transmission loss differences between scenarios, valued at Thailand long-term marginal generation cost of US$0.04/kWh (based on a 12% discount rate).
- Benefits from improved reliability associated with interconnection and the increased use of hydroelectric generation. Assigning a value to these benefits is complex, but basically the Plan develops an equivalent permissible reduction in thermal generation capacity that would be made possible by the higher reliability.
- Benefits from reduction in operating reserves associated with interconnection and the increased use of hydroelectric generation. The value of these benefits was estimated as being due to the reduction in hydroelectric operating costs as compared with thermal operating costs.

Excluded Costs

Control Centre Costs

The Plan does not appear to account for the cost of implementing or upgrading control centres. There are two approaches that could be used for control of the integrated system: national control centres for each of the participating nations, and one regional control centre (with backup control centres in all cases).

If national control centres are to be used, only Viet Nam, Yunnan and Thailand already have hierarchical control centres. With the possible exception of Viet Nam, which apparently does not have remote control capabilities, these countries may have all necessary capabilities for non-market operations. If so, the additional capital costs for each of them could be of the order of US$5M - US$30M[5]. The low-end figure would allow for minor control system communications, database, software and hardware upgrades, whereas the high-end figure would allow for significant primary control centre upgrades and some backup control centre capability (assuming suitable backup capabilities are not already available).

[5] All figures given in this section are ballpark, based on two North American systems. They should be used only to get an order of magnitude for the possible costs.

Cambodia and Lao PDR do not have adequate control facilities, so the additional costs would be significantly higher. Myanmar probably does not have suitable control facilities, but presumably won't participate in the interconnected grid (assuming the plant at Tasang is integrated into the Thai grid, so that control is from Thailand). The costs for Cambodia and Lao PDR (and Myanmar if it were to participate in the grid) could be as high as US$30M - US$40M each.

It is possible these costs could be reduced somewhat by development of shared backup facilities, although these would almost certainly complicate operations greatly, and would unquestionably require extremely close cooperation.

Another way of reducing these costs is through implementation of a single primary and backup control centre for the entire GMS, again requiring very close cooperation. This could be politically difficult, since then each GMS country would have to give up sovereignty over operation of their electricity grid. Islanded operation (where the grid becomes segmented, probably at or near interconnection points) would then be very complex.

Total additional costs with independent control centres, with backup facilities, could be US$75M-US$170M.

Costs would be higher (by perhaps US$40M or more) with implementation of an electricity market due to additional (custom or customized) software, hardware, etc.

Given the current lack of regional interconnection experience and considerable diversity in regional capabilities and facilities for operating transmission grids (even without interconnection), it could take up to ten years to commission and staff the necessary control centres.[6]

Water Usage Costs

The Plan appears to make no allowance for water use charges with hydro power[7]. Although current practice in the GMS countries may be to make no charge for water use or storage where the generation is used for national consumption, water is a national resource and some royalty for its use (along with the use of the reservoir space) is appropriate where the energy is being exported.

Even if a water use fee were applied only to the increase in hydro generation from Scenario 1 to Scenario 2B, the additional operating cost by 2020 would be $196M/year[8].

Transitional Costs

As identified in the Plan (Volume III-A, Chapter 3) interconnection will require harmonization of technical planning and operating standards and practices across the

[6] One could speculate that a fast-track approach might be to initially operate the regional grid from, for example, Thailand. Control for each nation’s grid could be transferred back to that nation as the control centres were commissioned.

[7] In the Canadian province of British Columbia there is a water rental fee payable to the Provincial Government. For fiscal 2004/05, B.C. Hydro is forecasting payments of approximately US$202M on production of 46635 GWh, or US$0.004/kWh.

[8] Computed using an example water rate of $0.004/kWh and the figures of 147 TWh (Scenario 1, from Table 4-10 in Volume III-A) and 196.0 TWh (Scenario 2B, from Table 4-20) for hydro generation in 2020.

GMS region. The costs and time associated with reconciling operating and planning practices among participants do not appear to have been included in the Plan. While for many of the required (non-construction) activities the cost may not be large relative to the total expansion cost, the time required can be considerable[9].

The following harmonization activities (among others) can be expected:

- Development of harmonized multi-national planning and operating guidelines[10].
- Engineering studies to develop specific multi-lateral operating plans for interconnected operation.
- Engineering studies to determine appropriate harmonized equipment settings, manual and automatic load shedding schemes, etc.
- Training for planning, operations and maintenance staff, including both training development and delivery.

As an outcome of the new agreements and studies, changes may be required to remedial action schemes (e.g. any load shedding schemes, probably only involving Thailand, Viet Nam, and perhaps Yunnan), requiring engineering studies and possibly construction work. Costs for these schemes were not included in the Plan and can be estimated only when the necessary studies have been completed.

There will also be costs of developing governance and regulatory structures.

Regulatory and Reliability Coordination Requirements

To provide the increased oversight requirements imposed by the Extended Cooperation scenarios, there is a need for national regulators (to protect consumers) and an international reliability organisation with legal enforcement powers (to protect reliability). While the author cannot offer insight into the cost of establishing these bodies, it is clear from the requirements and from experience in other jurisdictions that considerable time will be required to enact the necessary legislation, and develop and staff the required organisations.

Strong Independent Regulation

As pointed out in Volume IV of the Final Report, there is a need for regulatory oversight of monopolistic functions, particularly for the "natural monopoly"[11] function of transmission operation. In systems that depend on long-distance power transmission, the transmission operation function exerts overwhelming control over operation of the entire power system. The viability of any of the Extended Cooperation scenarios will ultimately depend on the performance of this function.

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[9] As a measure of complexity of the work involved, the Operating Manual of the North American Electric Reliability Council (NERC, www.nerc.com) consists of 620 pages. This is an example of only one of many documents which would have to be developed through multi-lateral technical discussions.

[10] See, for example, the NERC Planning Standards at ftp://www.nerc.com/pub/sys/all_updl/pc/pss/ps9709.pdf and Operating Manual at ftp://www.nerc.com/pub/sys/all_updl/oc/opman/opman.pdf .

[11] Transmission and distribution functions are generally viewed as "natural monopolies".

The regulatory bodies, established through an enabling act by each government, would be required to approve major capital investments (e.g. building a new 500 kV transmission line). Investments would only be included in the rate base (thus allowing cost recovery under a tariff) if the regulator were convinced these investments would reduce long-term power supply costs. Since regulatory bodies are national in scope, several regulators would become involved in approving interconnections.[12]

The need to develop uniform regulatory oversight in each nation of the GMS region[13] could impose a delay of several years on implementation of the Plan. Even after the required national legislation has been drafted and approved, there is still a need to form and staff the regulatory organization; develop rules, regulations and procedures; etc.[14]

Reliability Organisation with Enforcement Powers

In addition to the need for regulatory oversight of monopoly functions, there is a need for a reliability body with legal enforcement powers, such as the North American Electric Reliability Council (NERC) in North America.[15] To be effective this body would have to be trans-national and have the authority and responsibility to audit operating and maintenance practices and assess substantial financial penalties for violations.

The importance of such a body was emphasized by the latest large blackout in the US and Canada. This event involved seven violations of NERC reliability standards, according to the report from the bi-national investigating task force. This report also firmly states the requirement for enforcement powers. Quoting from the report's cover letter to the US President and Canadian Prime Minister:

> "The report makes clear that this blackout could have been prevented and that immediate actions must be taken in both the United States and Canada to ensure that our electric system is more reliable. First and foremost, compliance with

[12] Even with state ownership of utilities, independent regulators are required to protect consumer and other stakeholder interests.

[13] The surprising variability of the current regulatory situation in the GMS region can be seen by comparing Cambodia, which has only 150 MW of installed capacity and an electrification rate of 13%, with Thailand, which has 22,300 MW of installed capacity and an 82% electrification rate. Cambodia has been working to establish effective regulatory oversight for several years, while Thailand has no effective regulatory oversight and almost certainly will not have by at least the end of 2004. (The Plan is intended to cover 2005 to 2020).

[14] See http://www.eac.gov.kh/ and http://www.bcuc.com/ for example regulators. Note that regulation in some countries (e.g. the US) is hierarchical (on a national and state/provincial level), so not all regulators perform all regulatory functions. FERC (http://www.ferc.gov/) in the US, for example, is a national regulator and does not approve transmission construction, which comes under state jurisdiction. See http://psc.wi.gov/ for an example of a US state regulator.

[15] See www.nerc.com for more information.

> reliability rules must be made mandatory with substantial penalties for non-compliance.”[16]

For the GMS nations such a reliability body is especially important due to the lack of interconnection experience in the region, and especially the lack of experience with operation of a transmission grid in Cambodia and Lao PDR, which isolate the more-experienced nations of Thailand and Viet Nam, and thus would play a critical role in any interconnection.

Operation of an interconnected system is extremely complex in that critical information must be available to decision makers continuously and immediately, and decisions must be made within minutes on a 24 hour 7 day/week basis[17].

The August 2003 North American blackout demonstrated the enormous damage potential inherent in operation of an interconnected grid, where a utility with 4.4 million customers and 13,387 MW of peak load[18] created an outage affecting some 50 million customers and 61,800 MW of load[19]. The well-accepted advantages of interconnecting transmission grids come at the price of higher risk, which must then be mitigated through an uninterrupted focus on reliability.

The report on the August 2003 North American blackout provides helpful insight into the factors that lead to widespread blackouts on interconnected systems. While this list was prepared by considering North American blackouts, the same or similar factors can be found in reports for widespread blackouts in other parts of the world.

> “The blackout on August 14, 2003, had several causes or contributory factors in common with the earlier outages, including:
>
> - Inadequate vegetation management
> - Failure to ensure operation within secure limits
> - Failure to identify emergency conditions and communicate that status to neighboring systems
> - Inadequate operator training
> - Inadequate regional-scale visibility over the power system
> - Inadequate coordination of relays and other protective devices or systems.

[16] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, 5 April 2004. ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/ch1-3.pdf
[17] The *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* provides further explanations of both the difficulties of operating an interconnected grid and how failures to act quickly and correctly led to the collapse August 2003.
[18] Data from First Energy Corporation website: http://www.firstenergycorp.com/engine?s=com.firstenergycorp.www.Home&p=%2FCorporate+Profile%2FIndex
[19] See NERC’s “Press Briefing Talking Points - August 15, 2003 11:00 a.m.” at ftp://www.nerc.com/pub/sys/all_updl/docs/pressrel/talking-points-08-15-03.pdf

> New causal features of the August 14 blackout include: inadequate interregional visibility over the power system; dysfunction of a control area's SCADA/EMS system; and lack of adequate backup capability to that system."[20]

Interconnection of transmission grids introduces challenges that are either new or more difficult because of the interconnection. Planning and operation of the interconnected systems must be coordinated over all systems. The nature of the engineering studies required become significantly more complex with the need to deal with transient stability, dynamic stability and voltage stability over a large region[21]. Implementation of automatic protection schemes becomes more complex due to the need for improved co-ordination between protection schemes and devices, and increased risk if the schemes are not kept updated as the overall power system evolves. Communications (electronic and voice) of operating situations must occur continuously and without delay, error or confusion.

While each of these challenges can be overcome, doing so requires long-term dedicated effort. Because the expertise must, to be effective, reside with the operating utilities, bringing in consultants can provide only limited time savings. In the end, it is the actions of operating staff in the control rooms, who must make correct decisions involving a complex system in a very few minutes, which separates consumers who are blissfully unaware of their electrical dependence from a devastating economic impact.

Summary

The *Indicative Master Plan on Power Interconnection in GMS Countries* proposes extended power cooperation development of the electric power systems of the countries of the Greater Mekong Sub-region. The Plan anticipates savings of US$914 M for Extended Cooperation Scenario 2B as compared with the comparison Scenario 1 involving limited cooperation. The savings anticipated with Scenario 2B appear to derive largely from the substitution of hydroelectric generation for thermal generation.

While the Plan's economic analysis includes the construction- and operation-related costs for system expansion, it does not include the costs required to transition the GMS nations from loosely connected independent systems into a highly interdependent operating structure capable of constructing, maintaining and operating a rapidly growing power system.

In particular there does not appear to be any allowance for the time and cost involved in construction of the required control centres, implementation of any necessary remedial action schemes, harmonization of standards and practices across the region, hiring and training of staff, or establishment of the regulatory and reliability bodies which are essential to success of the Plan. There also does not appear to be any allowance for a royalty or tax on the use of water for exported hydroelectric generation.

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[20] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, page 110.

[21] Chapter 2 of the *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* provides relatively simple explanations of some of these complex concepts.

Although the omitted costs would reduce the apparent economic benefit of the proposed Scenario 2B, it appears unlikely they would entirely eliminate it. The greater concern to the feasibility of the Plan may be the delay imposed by these omitted activities.