An Alternative to Thailand's Power Development Plan*

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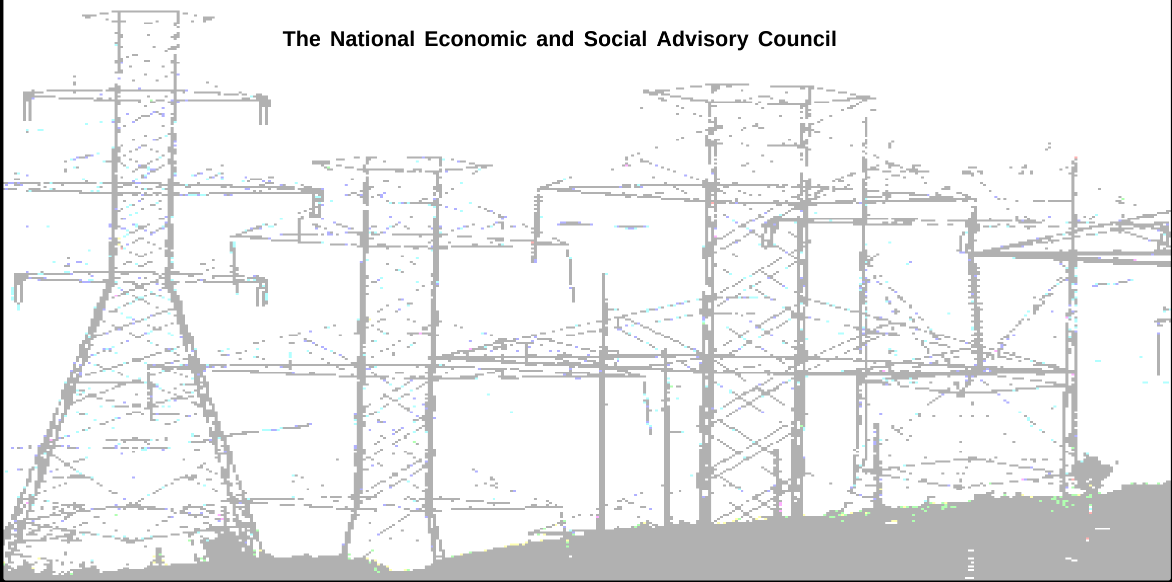

Electricity Generating Authority of Thailand's Power Development Plan (PDP) 2004, which was approved by the Thailand Cabinet, is based on an unrealistically high peak demand forecast. In addition, less expensive, environmentally or socially superior alternatives are not taken into consideration. The PDP is thus likely to lead to both over investment and misallocated investment. The failings of the PDP indicate that the narrow criteria that EGAT employs for planning are inadequate for the critical task of determining Thailand's power sector investment priorities in a way that is best for the country. The PDP should be revised and the process by which the PDP is determined should be amended to include broader criteria and meaningful public participation. Below is an alternative PDP, presented with a discussion of the specific failings of the PDP 2004.

1. Revise Peak Demand Forecast

1.1 The January 2004 power demand forecast, which was used as the basis for planning the PDP, has already over-predicted the 2004 peak demand by 274 megawatts (MW). The projected demand was 19,600 MW, but the actual peak was only 19,326 MW. The forecast should thus be revised by using the actual 2004 peak figure as the base for projecting demand in future years.

1.2 The forecast was made under the assumption that Thailand's annual GDP growth rate would maintain at 6.5 per cent for the next 13 years. This rate is extremely optimistic, considering the high oil price situation unforeseen at the time of the forecast completion and the fact that the average actual GDP growth rates during past the 10 and 15 years were only 3.6 per cent

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Table 1 Adjusted Peak Demand Forecast

Year	Jan 04 Forecast		Adjustments to Jan 04 forecast (MW)					Forecast (adjusted)
	Assumed per annum GDP growth rate	Peak Demand (MW)	Use actual 2004 peak as base (19,326)	GDP Growth = 5.6% (average past 15 years)	Demand: GDP = 1:1	Peak Cut (according to EGAT's PDP 2004)	Total (MW)	Peak Demand (MW)
2004	6.5%	19,600	-274	0	0	0	-274	19,326
2005	6.5%	21,143	-296	-35	-259	0	-590	20,553
2006	6.5%	22,738	-318	-110	-482	-500	-1411	21,327
2007	6.5%	24,344	-340	-227	-629	-500	-1696	22,648
2008	6.4%	26,048	-364	-373	-797	-500	-2034	24,014
2009	6.4%	27,852	-389	-577	-962	-500	-2429	25,423
2010	6.6%	29,808	-417	-903	-1113	-500	-2933	26,875
2011	6.5%	31,844	-445	-1280	-1252	-500	-3477	28,367
2012	6.5%	33,945	-475	-1731	-1343	-500	-4048	29,897
2013	6.5%	36,173	-506	-2277	-1428	-500	-4711	31,462
2014	6.4%	38,515	-538	-2897	-1519	-500	-5454	33,061
2015	6.5%	40,978	-573	-3652	-1565	-500	-6290	34,688

and 5.6 per cent per year, respectively. Therefore, the GDP assumption should be revised to be more realistic by lowering to no more than the actual average of the past 15 years.

1.3 According to the National Energy Strategy Plan announced in August 2003, the Government plans to improve efficiency of energy use by improving the ratio of energy use to GDP to 1:1. The actual ratio of year 2004 for the power sector was already about 1:1 (peak demand increased 6.6 per cent and GDP was estimated to increase by 6.5 per cent). Yet, the forecast was based on the 1.3:1 ratio. This needs to be corrected to reflect the strategy plan and the existing growth rates.

1.4 The Peak Demand should be lowered by 500 MW, according to the Peak Cut programme as stated in the PDP 2004.

With all the above mentioned revisions, **the Peak Demand can be lowered by 6,290 MW** to the level of 39,891 MW, as shown in Table 1.

2. Revise the Electricity Generation Supply

2.1 Use the revised peak demand forecast from item 1;

2.2 After the demand forecast reduction, the power sector still needs to seek an additional power generation supply of 15,120 MW by 2011 in order to meet the reliability criteria of 15 per cent reserve margin (see Table 2). The new supply would best be provided by:

- Projects already under construction and having the contracts signed with EGAT, which amounts to 4,620 MW. Note: this figure excludes the Nam Theun 2 project in Lao PDR, whose purchase price will be as high as 1.80 baht/unit (inclusive of the designated transmission line routing cost) while there are concerns over the project's impacts and an uncertain guarantee of loans from the World Bank);

	Potential in Thailand (MW)	Capacity used in the Alternative PDP (MW)
DSM	2,500	1,500
Renewable	>12,300	2,200
Cogeneration	>3,000	2,500
Repowering	~7,700	4,310
Total	>25,500	10,510

- For the remaining new supply, instead of developing new risky, large-scale fossil power plants or large hydro dams, the PDP should give priority to lower cost, lower impact, lower risk resources, e.g. DSM [Demand Side Management], renewable energy, cogeneration, and repowering of existing plants. These sources are incorporated in the alternative PDP as follows:

2.3 If the power sector reform follows the National Economic and Social Advisory Council's proposal – which suggests that large industrial customers consuming more than 60 per cent of the country's total energy demand can directly negotiate their purchases with independent power producers (IPPs) – the state utilities will be hugely relieved of their obligations to supply power to serve increasing power demand.

The transition to allow major power users (including Medium General Service, Large General Service and Specific Businesses customers) to supply energy to meet their own load growth should happen gradually. There should be at least three years of preparation. Then, in 2008, the most well-prepared large users (approximately 1/3 of load growth from these groups) will procure the needed power supply or make power purchase agreements with IPPs directly to meet their additional power requirements. The proportion of large customers responsible for their own load growth will increase to 2/3 and 3/3 of all their new demand in 2009 and 2010, respectively. Some large users who are not ready to procure power to meet their new demand themselves can still buy power from the state (EGAT or electricity distribution authorities). The obligation to supply new power shall include the required reserve margin (around 15 per cent of peak demand).

Following the above steps, the Alternative PDP will result in:

- A decrease of the peak demand by 6,290 MW;
- Lowering the need for the overall sector's capacity expansion of 7,444 MW, from 22,546 MW to 15,120 MW;
- Lowering the (non-industrial) sector's obligation to supply new power generation to only 2,300 MW (from 16,885 MW) while the 8,200-MW demand of the industrial sector shall be managed by private investors;
- Eliminating the need for 20 new natural gas/coal/hydropower power plants (each with a 700-MW generating capacity), by developing other low-cost, low-risk, low-impact alternatives;
- Thus, lowering the obligation to expand the overall system's capacity investment (2004-2015) from 977,590 million baht (735,000 million baht for EGAT) as stated in the PDP 2004 to only 400,000 million baht (including the cost of investment in transmission system (about 100,000 million baht) and system expansion for the industrial sector).

Details of the Alternative PDP are presented in Table 2.

The calculation of the Alternative PDP budget was based on the following assumptions:

- The investment cost of a new power plant project (including the necessary transmission system upgrade) is 25 million baht per MW (according to the PDP 2004, the new thermal power plant in Songkhla costs 16,800 million baht/700 MW, or 24 million baht/MW [including the transmission system cost]).
- The cost of re-powering an existing power plant (including transmission system cost) is around 22 million baht/MW (which equals to the average of the costs of three re-powering projects – South Bangkok, North Bangkok and Bang Pakong power plants, according to EGAT's PDP 2004.
- The cost of the DSM programme amounts about one-fifth (5 million baht/MW) of the cost of building a new power plant.
- Renewable energy costs about twice the cost of a fossil-fuel-based power plant or around 50 million baht/MW (Biomass/biogas power plant costs around 48 million baht/MW)
- The construction cost of a co-generation power plant is approximately US$900,000/MW, or 36 million baht/MW.
- The investment cost for transmission system is the same as that in EGAT's PDP 2004, except that the transmission system cost of Nam Thuen 2 is excluded. Therefore, the figure is at 100,000 million baht which is very high and should be revised so that it reflects the reduced demand projection and number of new power plant projects.

Table 2: Comparison of EGAT's PDP 2004 and the Alternative PDP

Year	EGAT PDP 2004		Instal Capac (MW
	Project		
2003	*Project under construction/negotiations*		25,26
	Krabi Thermal Unit 1	340 MW	
2004	Lan Krabue Gas Turbine	122 MW	26,35
	Lam Takhong Dam Hydropower Units 1-2	500 MW	
2005	BLCP Power Co., Ltd. Units 1-2	1,347 MW	26,37
	Gulf Power Generation Co., Ltd.	700 MW	
2006	Ratchaburi Power Co., Ltd. Units 1-2	1,400 MW	26,37
	Small Power Producers (Renewable power)	151 MW	
2007	Small Power Producers (Existing purchase)	60 MW	28,58
	Lao PDR Project (Nam Theun 2)	920 MW	
2008	Total	5,540 MW	31,61
2009	*New Projects*		33,01
2010			34,81
2011	Re-powering 4 existing power plants	2,485 MW	37,01
2012	Construction of 20 new power plants	13,770 MW	39,47
2013	Renewable Portfolio Standard (RPS)	770 MW	42,41
2014			44,61
2015			47,34
	Total	17,025 MW	
	Total Additional Capacity	22,565 MW	

Installed Capacity as of December 2003	25,363 MW
Total Additional Capacity	22,565 MW
Power Plants decommissioned from the system	- 550 MW
Total Capacity in 2015	47,378 MW

Installed Capacity as of December 2003	25,363 MW
Total Additional Capacity	15,120 MW
Power Plants decommissioned from the system	- 550 MW
Total Capacity in 2015	39,933 MW

Installed Capacity as of December 2003
Total Additional Capacity
Power Plants decommissioned from the system
Total Capacity in 2015

On 30 November 2004, two independent economists and an energy analyst wrote a letter to the World Bank concerning key assumptions and methodlogy of the World Bank-commissioned study, the *Nam Theun 2 Project Economics Interim Summary Report*, which examined whether Nam Theun 2 represented the least-cost energy option for Lao PDR and Thailand. The letter, reproduced below, highlights some of the flaws in the report's core assumptions in the assessment of project risk, and in the calculation of the economic rate of return.

30 November, 2004

Mr. Jemal-ud-din Kassum
Vice President, East Asia and the Pacific Region
The World Bank
1818 H Street NW
Washington DC 20433 USA

Dear Mr. Kassum,

Re: assumptions used in the economics analysis of the Nam Theun 2 project

We have reviewed the *Nam Theun 2 Project Economics Interim Summary Report*[1] and have comments regarding the assumptions[2] used in the economic least cost analysis (pp. 7-8), in the assessment of project risk (pp 8-11), as well as those used in the calculation of the economic rate of return (pp. 12-15). We expect that addressing these comments would significantly change the findings reported in the *Interim Summary Report*.

Economic Least Cost Analysis

The economic least cost analysis uses PROSCREEN modeling, which indicates that combined cycle gas turbines (CCGT) next best alternative (after constructing Nam Theun 2) available to the Electricity Generating Authority of Thailand (EGAT). From our understanding, as implemented by EGAT, PROSCREEN considers only centralized conventional power plants when picking "least cost" options. Demand side management (DSM) and cogeneration are not among the options considered. A certain amount of pre-determined DSM is added as an exogenous variable, but PROSCREEN is not configured in a way in which it could pick DSM. Yet it is well known that DSM in Thailand is considerably cheaper than CCGT. EGAT's DSM program, for example, has provided over 735 MW [megawatts] of demand reduction at a cost of 0.5 baht (US $0.0125) per kWh [kilowatt-hour].[3] Since this is one third the economic cost of CCGT[4], the economic least cost analysis section of the report (currently page 7-8) should include aggressive DSM or DSM bundled with renewable energy/ cogeneration as an option.

Risk Analysis

Our comments on risk analysis focus on the historical bias towards cost overruns in large hydro-electric dams, and on the tendency of Thai load forecasts to overestimate consumption.

1. On page 10, the *Interim Summary Report* states that "World Bank internal research on the experience of hydro project investment costs suggests a range of plus or minus 30% around the base case estimate is valid at 25% PO (probability of occurrence)."

This statement implicitly assumes that the error between estimated and actual costs of large hydropower projects is random, and that estimates are equally likely to be high as they are to be low. This assumption conflicts with most published research on this topic. One of the most cited studies is a World Bank study performed by Bacon et al (1996). The comprehensive study investigates 70 hydropower projects financed by the World Bank between 1965 and 1986 and finds that the estimated values for costs were significantly biased below actual amounts, and that average cost underestimation for hydropower projects was 27 percent.[5]

The World Commission on Dams report (2000) cites a number of other studies with similar (and generally more pronounced) results: large dam projects usually have cost overruns, and seldom come in under cost. The WCD study calculates that an aggregation of the results of all of the studies yields an average cost overrun for 248 large dam projects of 54%.[6] The same study reports that the World Bank funded Pak Mun Dam in Thailand, commissioned in 1994, had a 68% cost overrun.

The published findings by the World Bank and WCD cited above suggest that the values and POs for the risk assessment in the *Interim Summary Report* should be shifted. Using basic statistics and data available in the Bacon study and other reports, it would be straightforward to develop much more realistic assumptions of values and POs based on actual experience. A reasonable approach might be to choose a base case assumption of a 27% cost overrun.

2. Similarly, the *Interim Summary Report* states (page 10) that: "Demand forecasting experience in Thailand and elsewhere suggests that at 25% PO, demand can be as much as 25 percentage points above *or below* estimate by the tenth year into the forecast" (emphasis added). These assumptions are not consistent with the documented historical bias in the relationship between actual consumption and Thai demand forecasts in the past 12 years in which the Thailand Load Forecast Sub-committee (TLFS) has issued demand forecasts. Table 1 below shows the over-estimation as a percentage of actual 2004 peak power demand for 11 base-case demand forecasts issued in the past 12 years. The table shows that demand forecasts for Thailand have tended to over-estimate demand – sometimes by more than 40%. Only one of the 11 base-case forecasts (the August 02 demand forecast) has so far underestimated demand, and did so only slightly (1.5%). It should be pointed out that the Aug 2002 forecast is still very young. The 2004 peak load was 19,325.8 MW.[7]

Thai electricity demand forecasts are driven by economic forecasts. However, the Government of Thailand forecasts GDP typically only for five years. Beyond these first five years, electrical demand forecasting depends heavily on assumptions that are nearly impossible to predict with any accuracy.

While it is true that some of the difference between forecast and actual consumption shown in Table 1 is due to the economic downturn in the late 1990s, there is no guarantee that similar economic downturns will not occur in the future. Escalating violence in the south, a weakening dollar (hurting exports), further increases in petroleum prices, resurgence of Asian bird flu, or any number of as-yet unknown factors could trigger lower than projected economic growth. Again, a reasonable approach would be to assume a base-case overestimation bias similar to historic values, rather than assuming (as the *Interim Summary Report* does) that there is no systematic bias.

Forecast name	Years elapsed since forecast	Forecast (MW)	Over-estima (MW)
Jun-93	12	22,690	3,365
Dec-94	10	22,690	3,365
Oct-95	9	23,654	4,329
Apr-96	9	27,330	8,005
Oct-96	8	26,645	7,320
Jun-97	8	25,171	5,846
Sep-97	7	23,685	4,360
Sep-98 (Base case)	6	19,611	286
Feb-01	4	19,913	588
Aug-02	2	19,029	-296
Jan-04	1	19,600	275

Table 1: Overestimation of peak electrical demand in 2004 compared with actual 2004 peak demand for each of 11 base-case forecasts issued by the TLFS since June 1993. Out of 11 forecasts, 10 have over-estimated demand. Derived from: Thailand Load Forecast Subcommittee (2004). Power Demand Forecast Report. (In Thai language). Bangkok. January.

Together, comments 1 and 2 regarding risk suggest that the chance of a “high project cost / low demand scenario” are more likely than the report acknowledges because the report relies on data that have a record of significant systematic bias towards underestimating project costs and overestimating electricity demand. The results of the existing risk analysis indicate that combinations of high project cost and low demand result in low project NPV [Net Present Value]. Clearly, making the adjustments suggested above in the NT2 “Cost Risk Matrix” would strongly reduce the probability-weighted NPV of the NT2 option. These trends would be further enforced by updating the cost assumptions used in the risk analysis (see *Interim Summary Report*, page 8, footnote 12).

Benefit/Cost analysis

Our comments on benefit/cost analysis refer to costs that have been left out of the analysis.

1. On pages 12-15, the report calculates the economic benefit of the project by using end-use GWh [gigawatt-hour] multiplied by consumer willingness to pay minus marginal transmission & distribution costs and losses. This calculation overestimates benefits from NT2 because it neglects to subtract the utilities' costs of providing generation reserve margin (minimum 15% in Thailand), system operation (dispatch, reliability), utility administration, and system planning. In addition, in calculations of project cost (page 6) it is not clear if economic costs of the transmission line from NT2 to the Thai border, and transmission lines from NT2 to Lao load centers are included.

2. The study's calculation of economic costs includes only the project's investment, O&M [Operation and maintenance], and environmental and social (E&S) management costs. This omits the real costs of E&S impacts even after the mitigation measures, such as (permanent) loss of ecological habitat, biodiversity, and culture. While these may be difficult to calculate (willingness to accept, replacement value), they are certainly not zero as the *Interim Summary Report* assumes.

Thank you in advance for taking these comments into consideration when considering or updating the economic valuation of the NT2 project.

Sincerely,

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cc: World Bank Executive Directors
Mr. Ian Porter, World Bank Thailand Country Director

1 http://siteresources.worldbank.org/INTLAOPRD/Projects%20and%20Operations/20246496/Consultations_2004_Economics.pdf

2 One difficulty we had with the *Interim Summary Report* was that virtually none of the data or assumptions are referenced. Like the World Bank, we are interested transparency and accountability, and referencing sources of information is an obvious first step. A second difficulty we had is that most tables lack sufficient detail to trace the calculations. This could be easily reconciled by posting all relevant spreadsheets online and listing urls to these spreadsheets in reports.

3 Phumaraphand, N. 2001. Evaluation Methods and Results of EGAT's Labeling Programs. Presentation at the conference, *Lessons Learned in Asia: Regional Conference on Energy Efficiency Standards and Labeling*. Organized by Collaborative Labeling and Appliance Standards Program (CLASP) and the United Nations Economic and Social Commission for Asia and the Pacific (ESCAP). Bangkok, Thailand. 29-31 May. Slide 13. http://www.un.org/esa/sustdev/sdissues/energy/op/clasp_egatppt.pdf. See also: EGAT (2002). Demand Side Management. Annual Report. http://pr.egat.or.th/ann_eng/Eng%2034-35.pdf

4 Economic cost of CCGT is estimated to be US$ 0.038/kWh in *Interim Summary Report,* page 7.

5 Bacon R.W. et al (1996) "Estimating construction Costs and Schedules. Experience with Power Generation Projects in Developing Countries" World Bank Technical Paper No.325, WB, Washington D.C. Page 53. Available at: http://www-wds.worldbank.org/servlet/WDS_IBank_Servlet?pcont=details&eid=000009265_3961219094408

6 World Commission on Dams (2000). Chapter 2: Technical, Financial and Economic Performance. *The Report of the World Commission on Dams. WCD*. London, Earthscan Publications Ltd. Page 41. Available at: http://www.dams.org/report/contents.htm

7 EGCO (2004). Power Market Monitoring. http://www.egco.com/PowerIndustry/PowerIndustry_Home.asp