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29 March, 2005

The World Bank
1818 H Street NW
Washington DC 20433 USA

Dear World Bank Executive Directors,

Re: Remarkable unjustified assumptions in economics analyses of the Nam Theun 2 project call for independent review of Nam Theun 2 economics

We (two Thai University Economists and a Ph.D. power sector analyst) are writing to you to express our concerns regarding the quality of two main World Bank's economic analyses of the Nam Theun 2 hydropower project: *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Final Report*¹ and the *Lao PDR Nam Theun 2 Hydroelectric Project: Project Economic Analysis*.² The final versions of these studies, released just last week, contain two remarkable new assumptions regarding assumed costs of natural gas alternatives that are crucial in justifying the Bank's continued positive economic assessment of the Nam Theun 2 (NT2) project. These assumptions are suspicious because they are changed without explanation or justification from earlier versions of the studies, because the changes are large in magnitude, because the changes systematically favor NT2, and because the changes follow in the wake of an increase in the PV of the NT2 economic capital cost from US\$581.4 million to US\$682.3 million.³

In addition to these new assumptions, there are several key assumptions that are carried over from previous versions of the studies that we find exceptionally problematic because they defy the principle of equal valuation for equal products, because they contradict the EGAT power development plan upon which the studies are based, and because they are strongly different than conclusions from other World Bank-commissioned NT2 studies.

Crucial and remarkable unjustified assumptions in the Final versions of the reports are summarized below. For details and references please see the attached appendix.

High natural gas cost increase (changed from previous report version without justification). The economic least-cost analysis assesses Nam Theun 2 against electricity from natural gas. The World Bank's *Final Economic Least-Cost Analysis* includes a 61 percent increase in the assumed real economic cost of natural gas starting in year 2016, compared with the Draft Final Report (June 2004)

¹ Robert Vernstrom, 2005. *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Final Report*. March. url: <http://siteresources.worldbank.org/INTLAOPRD/Resources/RELC-2005-final.pdf>

² World Bank, 2005. *Lao PDR Nam Theun 2 Hydroelectric Project: Project Economic Analysis*, March 14. url: http://siteresources.worldbank.org/INTLAOPRD/Resources/Annex_11A.pdf

³ Table 17 of *Least-Cost Analysis* (p. 42 of Draft Final and p.44 of Final). The increases reflected in changes in table 17 between the Draft Final and Final versions of the report do not yet take into account the latest increases in nominal project cost by the Nam Theun 2 Power Company Ltd (NTPC), which now stands at \$1250 million (*Project Economic Analysis*, footnote 25, page 21.)

version of the report⁴. There is no justification for this increase provided in the text. This unexplained increase in natural gas costs comes just 6 years after Nam Theun 2's planned commissioning date, and extends throughout the duration the project evaluation (year 2032), resulting in a considerably more favorable (but unjustified) assessment of Nam Theun 2 compared with electricity from natural gas;

Gas turbine capital cost increases (changed from previous report version without justification):

The Final *Economic Least-Cost Analysis* states in the text that “bank-recommended values of \$US250/kW for GT [gas turbine] capacity and US\$450/kW for CCGT [combined cycle gas turbine] capacity have been adopted.” While the Draft Final Report version of the study uses these correct figures, they have been inexplicably changed in the spreadsheet tables in the Final version of same report to \$310/kW and \$510/kW respectively. No justification is provided for these 15% to 16% increases in capital cost. These unexplained increases make electricity from natural gas appear less competitive compared to NT2.

Mis-valuing of reduction in firm power from Theun Hinboun. Nam Theun 2 will result in an annual reduction of 275 GWh of firm energy from the Theun-Hinboun hydropower project situated 40 km downstream from Nam Theun 2. The *Project Economic Analysis* assigns a value of US 7 cents/unit for firm Nam Theun 2 power, but only US 2.3 cents/unit to the lost (firm) power from Theun-Hinboun, with no explanation given for why firm power from these two Lao hydropower projects would be valued so differently.

No accounting of 1,499 MW of additional least-cost DSM and renewable energy. A recently-released World Bank-commissioned study concludes that “a careful accounting of the realistic potential of Demand Side Management (DSM), energy efficiency, and firm renewable resources within Thailand indicates an achievable amount of 1,499 MW of DSM/EE and firm RE resources – beyond what is included in the existing power development plan (PDP) -- at a commercial cost less than NT2.” Yet the final versions of *Project Economic Analysis* and *Final Economic Least-Cost Analysis* fail to incorporate these estimates into their assessments of alternative options for meeting Thailand's energy needs. None of this 1,499 MW of additional achievable potential is included in the modeling in the final versions of the economic studies.

Omission of committed upgrades and overestimation of plant retirements. The *Project Economic Analysis* and the *Final Economic Least Cost Analysis*, in their assessment of Thailand's future energy needs, omit from their calculations 2,100 MW of planned new domestic capacity from Thailand's April 2003 Power Development Plan (PDP), and 5,863 MW from the country's current PDP. This amount is almost six times the capacity of NT2. Taking into account these planned additions makes Nam Theun 2 unnecessary and burdensome for the Thai consumer.

Each of these issues is significant, and each is easily verifiable (see appendix). Correcting these will significantly impact the economics of the project. Together, these inconsistencies and new unjustified assumptions call into question the entire economic analysis of Nam Theun 2 and lead to the necessity of an independent review of the economic appraisal of Nam Theun 2 before the World Bank Board votes on the project. We urge you to push for such a review before approving the project.

Sincerely,
(see list below)

⁴ Robert Vernstrom, 2004. *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Draft Final Report*. June. url: <http://siteresources.worldbank.org/INTLAOPRD/491761-1094074854903/20251513/Economic.pdf>

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

Appendix: details of inconsistencies and unjustified assumptions in the final version of World Bank economic analyses of Nam Theun 2

Remarkable and unjustified natural gas fuel cost increases

Assumptions about the real economic cost of natural gas fuel in the Draft Final (June 2004) and Final (March 2005) versions of the *Least Cost Analysis* report are shown below in Figure 1. In the Draft Final version of the report, real economic costs in years 2014-2034 are assumed to be nearly constant at \$US 2.27/mmbtu. In the Final version of the report they escalate sharply in year 2016 (six years after Nam Theun 2 commissioning) to \$US 3.65/mmbtu and remain fixed at this high level for the next 18 years (table 15, page 33). There is no justification provided in the text of the Final *Least Cost Analysis* provided for the 61% increase from the Draft to Final versions of the report. Indeed, the only justification for natural gas prices in these years in the text of the Final *Least Cost Analysis* contradicts the actual values used in the analysis and appears to be left over from the earlier draft: “for the end effects period 2014-2034, in the economic analysis the value achieved by 2014 is sustained in real terms” (page 90 of Appendix A3).

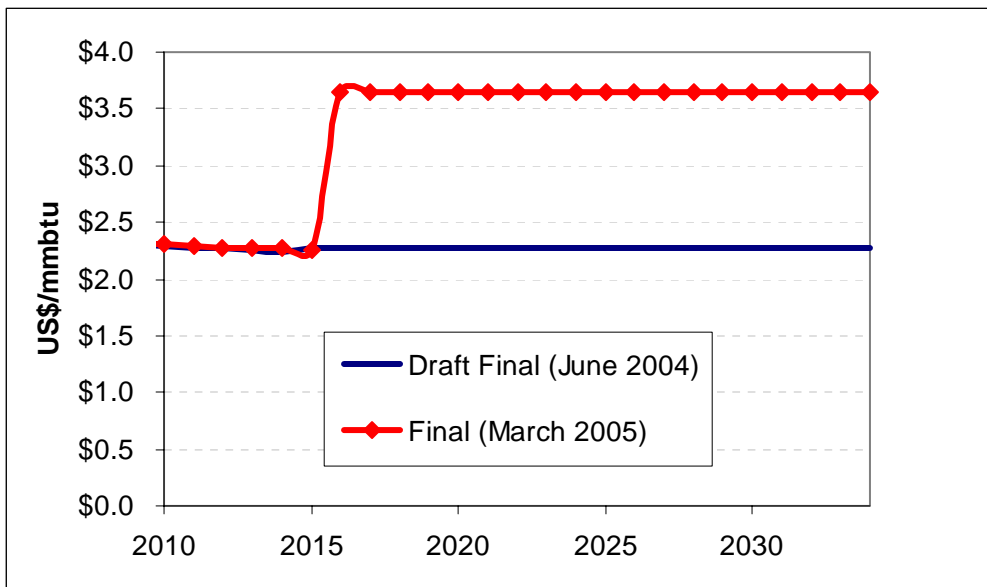


Figure 1: Comparison between real economic natural gas prices in the *Draft Final* (June 2004) and *Final* (March 2005) versions of the *Regional Economic Least Cost Analysis*. Source: Table 15: Screening analysis of EGAT Candidate Plants (page 30 of Draft Final and page 33 of Final)

Unjustified gas turbine capital cost increases

Page 28 of the Final *Least Cost Analysis* states that “Bank-recommended values of \$US250/kW for GT [gas turbine] capacity and US\$450/kW for CCGT [combined cycle gas turbine] capacity have been adopted.” Yet this statement contradicts the figures used in the actual calculations in the same report, which are \$310/kW and \$510/kW for GT and CCGT, respectively (Table 13 on page 29 and Table 15 on page 33 of the Final *Least Cost Analysis*). In the Draft Final version of these same tables, the costs are \$US250/kW and US\$450 as they should have been, suggesting deliberate increases for the Final version of the report. Again,

there is no justification provided for these significant increases. These unexplained increases make GT and CCGT less competitive compared to NT2.

Mis-valuing of reduction in firm power from Theun Hinboun

Diversion of water used to produce electricity at NT2 will cause the Theun Hinboun dam 40 kilometers downstream to lose 275 GWh per year of energy production. The *Project Economic Analysis* values NT2's firm energy (PE) at US cents 7 per kWh (page 20) but values Theun Hinboun's loss of (firm) electricity at only US cents 2.3 per kWh (page 22), the same as NT2's non-firm electricity. There is no justification provided for why firm power from NT2 is more than three times more valuable than firm power from Theun Hinboun.

No accounting of 1,499 MW of additional least-cost DSM and renewable energy

The final versions of both the *Project Economic Analysis* and the *Least Cost Analysis* both fail to incorporate *any* of the clean energy potential that a recently released World Bank-commissioned study concludes is achievable at commercial cost less than NT2. The *Project Economic Analysis* offers only an illogical dismissal of additional DSM.

The recently released World Bank-commissioned study *Nam Theun 2 Hydropower Project (NT2): Impact of Energy Conservation, DSM and Renewable Energy Generation on EGAT's Power Development Plan (PDP)*⁵ concludes that: "A careful accounting of the realistically potential of Demand Side Management (DSM), energy efficiency, and firm renewable resources within Thailand indicates an achievable amount of 1,499 MW of DSM/EE and firm RE resources – beyond what is included in the existing power development plan (PDP) -- at a commercial cost less than NT2. If non-firm RE resources are included, this adds an additional 1,195 MW of non-firm RE capacity." The amount included in the PDP is 982 MW of DSM and 197 MW of renewable energy⁶.

Versions of this study were available to World Bank economists since August 2004, a month after the July 2004 Draft Final *Least Cost Analysis* was released. None of the additional 1499 MW of low-cost clean energy potential is included in the final version of *Least-Cost Analysis*. The definitive tables for load forecast and committed plant additions are table 9 (page 24 of Final *Least Cost Analysis*) and table 11 (page 27 of the Final *Least Cost Analysis*). These tables are identical in Draft Final and Final versions of the report, and include the original 982 MW of DSM and 197 MW of renewable energy included in the PDP.

Energy conservation in the *Least Cost Analysis* is discussed in a section starting on page 14 of the Final version. The section is word-for-word identical to the section from the Draft Final version.

⁵ du Pont, P. (2005). *Nam Theun 2 Hydropower Project (NT2) Impact of Energy Conservation, DSM, and Renewable Energy Generation on EGAT's Power Development Plan*. Bangkok, World Bank. March 24. <http://siteresources.worldbank.org/INTLAOPRD/Resources/DSMmarch2005.pdf>

⁶ du Pont, *Impact of Energy Conservation* page 5, *Regional Economic Least Cost Analysis* page 25, table 11.

There is no incorporation of additional DSM /energy efficiency energy in the *Project Economic Analysis*. The study offers only the following brief dismissal:

“Achieving DSM potential depends upon the efficacy of intentional programming and the response of millions of electricity consumers... This consideration makes it reasonable to consider this incremental 1279 MW⁷ of demand side management as part of the demand risk analysis. Seen in this context, the additional 1279 MW would change peak demand in 2010 from 27,263 MW to 25,984 MW, thereby reducing the base case demand growth rate between 2002 and 2010 from 6.6 percent per year to 6.0 percent per year; however, the low case demand growth rate adopted for sensitivity testing in the analysis for this PAD is 3.4 percent per year over the same period. Hence this uncertainty about the extent of additional DSM is a small part of the already assumed demand uncertainty range for the risk analysis in this document”. (page 5)

To paraphrase, the *Project Economic Analysis* author argues that “DSM may or may not happen. If it does happen, it reduces demand by only 0.6 percent. But we already consider more than that in the risk analysis that predated the *NT2 Energy Conservation Study*.” The reasoning is flawed because the *additional* DSM leads to *additional* reduction in demand forecasts – beyond that included in old risk analysis.

In the economic modeling spreadsheets, the Final *Project Economic Analysis*, like the Final *Least Cost Analysis* includes only 928 MW of DSM⁸ and the 197 MW of renewable energy (page 8), the same amount assumed in draft versions of studies that predated the *NT2 Energy Conservation* study.

Omission of committed upgrades and overestimation of plant retirements

The Final *Regional Economic Least-Cost Analysis* compares two supply expansion scenarios: one with Nam Theun 2, one without Nam Theun 2. In developing the two scenarios, the study, which is based on the April 2003 Power Development Plan (PDP) (Final *Least Cost Analysis*, page 25) omits 2,100 MW of committed upgrades at EGAT’s existing power plants that will come on-line before NT2 planned commissioning in 2010. The planned PDP (April 2003) upgrades that were omitted in the Final *Least Cost Analysis* comprise the following CCGT natural gas plants: North Bangkok (700 MW), South Bangkok (700 MW), Songkla (700 MW). In addition, the Bang Pakong 700 MW CCGT plant will come on-line in 2011. There is not justification provided for the omissions.

In 2004, the government approved EGAT’s new investment plan, PDP 2004⁹, with even more committed plants to be commissioned before 2010, the year that NT2 is planned to come on line. EGAT’s planned capacity retirements have also changed. Taking these into account, the discrepancy between the Final *Least Cost Analysis* and the current 2004 PDP is 5,863 MW, or almost six times the capacity of NT2.

⁷ 1279 MW comes from a December 21 version of the *NT2 Energy Conservation* study.

⁸ “928 MW” appears to be a typographical error based on the 982 MW of DSM adopted in the *Least Cost Analysis*

⁹ EGAT 2004. *EGAT Power Development Plan 2004-2015 (PDP 2004)*, July.

The World Bank

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March 30, 2005

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Dear Dr. Greacen, Khun Decharut and Dr. Chalotorn:

Subject: NT2 – Project Economic Analysis

I am writing to respond to the claims in your letter (dated March 29, 2005) to the World Bank's Executive Directors that the World Bank has purposefully used "suspicious assumptions" and "changes [that] systematically favor NT2" in its economic analysis of the NT2 project. This letter explains why these claims are unfounded.

The Bank's economic analysis draws on actual market prices in ascribing real economic values and costs. Market prices are constantly changing and, therefore, it is standard practice for the bank to adjust its assumptions and economic analysis periodically to reflect such changes and to remain up to date. There have been two significant changes that are reflected in the Bank's new economic analysis for the NT2 project: (i) an increase in global oil prices and futures prices, which also influence gas prices; and (ii) an increase in the cost of capital goods related to the power sector.

In order to ensure the accuracy of its economic analysis, during the second half of 2004 and the first few months of 2005, the Bank revisited all of the major assumptions for its economic and commercial analysis. Each of these assumptions was retested and adjusted individually based on the respective merits. The consultations process of August-September 2004, during which the Bank received views and advice from a broad spectrum of knowledgeable people, contributed to some of the revisions. Some of the changes in assumptions were substantial, others less so.

Cost of Natural Gas. *The economists state that the Bank increased the cost of natural gas without justification.* The major sources of changed natural gas values between the Bank's August 2004 Interim Economic Analysis and the March 2005 Project Economic Analysis are (i) a minor recalibration of the gas price determination formula to more accurately reflect current market costs in 2004, (ii) an increase in the World Bank's oil price forecast, which partially impacts the price of natural gas because the price of heavy oil has about a 30% share in the gas price indexing formulae of current contracts, and (iii) a revised treatment of gas pipeline transportation costs. For the economic costing of natural gas, items (i) and (ii) caused the value to increase, while item (iii) caused it to decrease. These changes were almost offsetting, such that

there is very little difference between the values for natural gas used last August compared with those used this year. Notwithstanding the information in Table 15 of the RLEC report, the Bank used a gas price of US\$2.27/mmbtu from 2015 onward. It is important to note that the Bank has looked at both spot market prices *and* long-term price trends in carrying out its analysis and has used sensitivity analysis to test the robustness of the project to changes in these prices.

Increased Cost of Gas Turbines. *The economists state that the Bank changed gas turbine costs from the previous economic analysis without justification.* The Bank carried out further due diligence on the capital costs of gas turbines (GT) and combined cycle gas turbines (CCGT). This included getting actual prices of CCGT projects recently completed in the Southeast Asian region. As a result, the GT capital cost increased from US\$ 250/kW to US\$ 310/kW and the CCGT capital cost estimate increased from US\$ 450/kW to US\$ 510/kW. For the CCGT capital cost, this represents a 13 percent increase above the previous estimated capital cost and reflects booming demand for capital investment in power generation in Asian markets and the resulting increase in the cost of capital equipment, factors which have also affected the capital cost of the NT2 project.

Valuing the Reduction in Firm Power from the Theun Hinboun Project. *The economists state that the Bank has mis-valued the reduction in firm power from the Theun Hinboun project.* The planning, design and construction of the Theun Hinboun (THB) project was predicated on the knowledge that the NT2 project – once constructed - would draw water from THB, which has used the incremental water available as a result of the delayed implementation of NT2 to generate additional power for export to Thailand. When NT2 is commissioned, there will be a reduction of energy but not of peak capacity from THB. The small (less than two-tenths of one percent of Thai energy demand) reduction of energy supply from THB is a supply displacement and replacement issue - not an element of incremental consumer demand. Therefore, it will be replaced by a minor increase of energy production from existing thermal power plants, at a lower marginal economic cost, estimated to be the recurrent operating and fuel costs of that capacity, because there will be no capital charges. In contrast, NT2 would provide a significant expansion of capacity designed to meet higher Thai power demand which would be valued, in economic terms, at the retail consumer's willingness to pay.

Accounting for 1,225 MW of Additional DSM and 274 MW of Renewable Energy. *The economists state that the Bank has given no accounting to the 1,499 MW of additional least-cost DSM and renewable energy.* The study on energy conservation, demand side management (DSM) and renewable energy in Thailand by Danish Energy Management is the last of the consulting studies that the World Bank commissioned as part of its due diligence on the economic aspects of the Nam Theun 2 Hydroelectric Project. The final version of this paper, which was commissioned in April 2004, was posted last week on the Bank's website. The Bank commented on earlier drafts of the paper in June and October 2004, and in January and March 2005.

The study estimates that in the period from 2002 to 2011, energy efficiency (EE) and DSM could provide as much as 1,225 MW beyond the 982 MW of DSM already included in EGAT's Power Development Plan (PDP) of August 2002, the planning base for the Bank's NT2 project economic analysis. The study also estimates that this energy would be less expensive than additional electricity supply from any source.

The Bank's economic analysis for the NT2 project recognizes these findings (see the interim and the final analysis on this website, posted respectively in August 2004 and March 2005). However, that analysis observes that it is uncertain how much of these estimated amounts of DSM/EE beyond those already included in EGAT's PDP might actually occur in the planning

period to 2011, because their achievement would depend on the independent and uncertain decisions of millions of Thai electricity consumers. During the first DSM program (a seven-year period from 1995 to 2001), EGAT achieved 638 MW in DSM savings, averaging about 90 MW annually. EGAT's current program assumes comparable results, totaling 982 MW of DSM/EE savings from 2002 to 2011. The author's assumption that EGAT could achieve an additional 1,225 MW of DSM/EE savings during the period assumes a 145 percent annual increase over the rates of uptake previously achieved and currently projected by EGAT. While such a result would be highly desirable, this is a rate of progress that cannot be predicted with reasonable assurance, given the potential institutional and funding uncertainties cited by the author.

The Bank recognizes that DSM/EE savings are a desirable outcome and should be encouraged; indeed, it pioneered DSM project support in Thailand in the 1990s. But there are practical constraints on the pace of implementation. In the event that all of the prospective DSM/EE savings were to be realized in the planning period, the author and the Bank conclude that it would delay the optimal NT2 commissioning date by about a year. This, however, does not destroy the project's long-term economic viability. The Bank's analysis concludes that NT2 would still be economically viable, with an economic rate of return (ERR) of 14.6 percent instead of an ERR of 16.3 percent.

The study also estimates that 274 MW of renewable energy projects would be likely to provide electricity at commercial costs below that of NT2. This amount fits within EGAT's supply planning parameters over the time period that includes NT2's commissioning date.

Omission of Committed Upgrades and Overestimation of Plant Retirements. *The economists state that the Bank omitted committed upgrades and overestimated plant retirements.* The supply program adopted in the Bank's analysis is economically optimized with dynamic programming related to the demand forecast used. All prospective plants that are not firmly and irrevocably contracted are treated as candidates for inclusion in the optimized supply program. This treatment is technically correct and realistically reflects the flexibility available to EGAT for adjusting its supply program over the remainder of the decade and beyond, in order to achieve a reasonable balance between demand and supply including required reserves.

I trust that this responds adequately to your expressed concerns.

Sincerely,

Ian C. Porter
Country Director, Lao PDR and Thailand
East Asia and Pacific Region

cc: World Bank Executive Directors

Mr. Ian C. Porter
World Bank Country Director
Lao PDR and Thailand East Asia and Pacific Region

Dear Mr. Ian C. Porter:

Re: Low credibility of Economic Least-Cost Analysis

Thank you for your rapid response to our letter to the World Bank Executive Directors concerning the large unexplained changes in key assumptions in the economic analysis of the Nam Theun 2 hydropower project. Serious issues remain unresolved that cast considerable doubt on the credibility of the project economic appraisal, as discussed below.

Cost of Natural Gas

We hope you understand our concern about the stated 61% increase in natural gas prices starting in year 6 of NT2's commissioning (shown in Table 15 of the *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Final Report*). The economic valuation of NT2 hinges on a comparison of the economic cost of electricity from NT2 versus electricity from natural gas. For generation from natural gas, fuel costs are the primary determinant of economic cost. Thank you for clarifying that the stated \$US3.65/mmbtu value is erroneous and that the actual value is \$US 2.27/mmbtu. We respectfully request your explanation for why such a large figure ended up in the Final version of the report that was accepted by the Bank.

Upon further inspection of Table 15 in the *Final Report* we noticed that the table also shows considerable change in the assumed values for O&M costs for combined cycle gas turbine (CCGT) and gas turbines (GT). In the *Draft Final Report* these values are defensible at US\$0.00056/kWh and US\$0.00042/kWh respectively. In the *Final Report* version of the table, these costs are increased 12.5 times and 10 times respectively, to US\$0.007/kWh and US\$0.0042/kWh respectively, again with no attempt at an explanation in the text. While variable O&M normally costs constitute a small fraction of total costs, the apparent *Final Report* assumption that these costs are equal to 37% of fuel costs would have a significant impact on the calculated economic competitiveness of electricity generation from gas turbines.

Can you specify for us and the Bank Board which of the key updated variables in Table 15 in the *Final Report* are erroneous and which are actually used in the economic model? The current situation in which the text discussion of these key variables in the *Final Report* reflect the *Draft Report* values; in which crucial values of variables in Table 15 are (according to your letter) not actually the ones used in the final analysis; in which the values of these variables are not found anywhere else in the report; and in which the spreadsheets themselves are not made available to the public make it impossible for the reader to figure out what values were actually used in the final economic appraisal.

What *can* be ascertained from the report is that the consultant finds that economic benefits of NT2 remains essentially the same (0.57% of project cost in the *Final Report* vs. 0.63% of project cost in the *Draft Final Report*), even though economic capital cost of NT2 escalates 17% from US\$581.4 million to US\$682.3 million *and*

for the first time the studies include economic costs arising from offsetting firm generation at the Theun Hinboun hydropower project downstream from NT2 (which we maintain are considerably undervalued).

It is clear that *something* big has changed in the analysis of natural gas in order to maintain the result that NT2 is economically favorable, and that this change occurs in the “end-effect” years following 2016, for which very little information is available from the *Final Report*. Between the *Draft Final* and *Final* versions of the study, the present value of “end-effects” costs in the “Base case without NT2” (Table 19) increases 14%, from US\$17,654 million to US\$20,145 million. If this is not due to an increase in natural gas prices, we request your explanation of the cause. Conspicuously, the present value of costs in the “planning period” (year 2003-2014) increases only 1.6% between the *Final* and *Draft Final* versions of the report. Thus these “end year effects” are crucial in the continued positive economic assessment of NT2 with respect to gas. Unfortunately, the details of these calculations are not available, as Appendix A6 details only cover the years 2003-2014.

Capital Cost of Gas Turbines

Thank you for your explanation of the basis behind the increased in the assumed capital cost of natural gas turbines. May we request that this explanation be reflected in the text of a “final final” version of the *Least Cost* report, as currently the text only explains the US\$250/kW (GT) and US\$450/kW (CCGT).

Valuation of Firm Power from Theun Hinboun

Regarding valuation of firm power from the Theun Hinboun (THB) hydropower project downstream from NT2, we are unconvinced by your explanation for why firm electricity from THB is valued less than 33% the value of firm electricity from NT2. THB has a contract to supply firm power to Thailand. NT2, if built, reduces the supply of water to THB, and therefore reduces the ability of THB to meet its obligation to supply firm power. It seems to us that a better explanation is needed for valuing firm electricity from THB at US cents 2.3 per kWh and NT2’s firm electricity at US cents 7 per kWh.

Accounting for 1,225 MW of additional DSM and 274 MW of firm renewable energy

We disagree with your explanation that none of the additional 1,499 MW of DSM/firm renewable energy capacity should be reflected in the economic modeling in the final studies “because their achievement would depend on the independent and uncertain decisions of millions of Thai electricity consumers.” The study on energy conservation, demand side management (DSM) and renewable energy by Danish Energy Management *already* heavily discounts the commercially viable DSM and renewable energy to arrive at achievable potential. The consultant’s 63 page study carefully arrives at achievable potential through two independent parallel methods. First, he conducts a sector by sector analysis and discounts published commercially viable these figures to arrive at achievable potential estimates that are typically 5% to 20% of the commercially viable potential for each end-use. Second, the consultant cross-checks this result by considering government DSM programs and discounts these by 25% (Electricity Generation Authority of Thailand - EGAT) and 75% (Department of Alternative Energy and Energy Efficiency). Both results match.

The figure of 275 MW of firm renewable energy is also heavily discounted. It includes only renewable energy that is commercially and economically *lower* cost than electricity from NT2, and is further discounted to arrive at achievable potential. This number does not take into account 2,700 additional MW that the report concludes are commercially viable under existing programs, nor additional potential that is expected under Thai government renewable energy policies currently under consideration in response to the Thai government's commitment that 8% of total energy come from renewable energy by the year 2011. New funds totaling US\$113 million have already been allocated to these new programs, in addition to US\$185 million earmarked for existing renewable energy subsidies programs.

The consultant who wrote the report is recognized as Thailand's leading energy efficiency and DSM expert, and conducted his Ph.D. research and his 20-year professional career focusing on DSM and energy conservation in Thailand. His specific credentials in the field would suggest that he is a better judge of the achievable potential of DSM and renewable energy than the consultant who wrote the economic appraisal – who discounts these results 100% to “zero additional potential”.

Omission of Committed Upgrades and Overestimation of Plant Requirements

Your reply argues that “all prospective plants that are not firmly and irrevocably contracted are treated as candidates for inclusion in the optimized supply program” and their omission as committed capacity in NT2 appraisal is therefore justified.

To provide context, we point out that the March 2003 version of the Power Development Plan (PDP) upon which the NT2 economic appraisal is based was never approved by the Thai government. The official 2004 PDP, which calls for 4,098 MW more capacity additions than NT2 version, provides a much more realistic basis for assessing Thailand's power plant investment decisions. The 2004 PDP was issued in August 2004. Given the importance of this plan, it should have been incorporated into NT2's economic appraisal.

Regarding the justification of omitting committed plants, we note that equipment procurement contracts have already been signed for at least the 700 MW EGAT CCGT plant in Songkla that was omitted from the NT2 Final Report. Revoking these contracts entails considerable costs that are not included in the NT2 project appraisal.

Your reply neglected to address our concerns with overestimation of plant retirements. The *Least Cost Final Report* assumes 2585 MW more plant retirements by the year 2014 than EGAT's current PDP.

Thank you for considering these points. There clearly remains considerable uncertainty on the results of the NT2 economic appraisal. We believe these warrant an independent review before the Bank Board approves the project.

Sincerely,

(list below)

31 March, 2005

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Dear Dr. Greacen, Khun Decharut and Dr. Chalotorn,

Your letter dated March 31, 2005 includes another series of statements which seem to either misconstrue statements which we have made in our previous letter to you (dated March 30, 2005) or reflect ongoing differences of opinion which we hope can be resolved.

I shall, once again, respond to each of your points, in order.

1. On the cost of natural gas and the reason why US\$ 3.65 remained in Table 15 of RELC:

The US\$3.65/mmbtu value of natural gas in Table 15 of the report on the Regional Economic Least-Cost Analysis for the Nam Theun 2 Hydroelectric Project (RELC) is not "erroneous" as you claim but the World Bank's current view of the long-term economic price of natural gas in Thailand. It was derived after a long and careful review of current and prospective demand and supply conditions facing the Thai natural gas market. The US\$3.65/mmbtu consists of US\$3.50/mmbtu for the gas (based on imports, be it in the form of LNG or dry gas from countries in the region) and US\$0.15/mmbtu for inland gas transmission. Natural gas at US\$3.50/mmbtu corresponds roughly with oil at US\$ 20/bbl.

The author of the RELC Report used that value for the screening curve analysis in his report to demonstrate that even if one used a higher long-term backstop value of natural gas reflecting the cost of current LNG contracts, CCGTs burning natural gas would remain the least cost thermal option for base load operation. We could have used this value in the least-cost analysis as well, with the result of making NT2 look even far more economically attractive than it already is. We refrained from doing so because of uncertainty about the extent and timing of long-term dependence on such sources of natural gas in Thailand, and a concern to not over-estimate the cost advantage of NT2.

2. On the values for variable O&M:

Capital costs and O&M costs for both CCGT and gas turbines were revised for the Final RELC report. As explained in our previous letter, we revisited all major assumptions for the economic and commercial analyses. As part of this due diligence, we received advice from private sector developers of independent power plants that our capital and operating cost estimates were too low in today's environment. Specifically, they were of the view that we had under-estimated the costs of various items such as insurance and, more importantly, the inspection and maintenance work that lenders insist upon as conditions of financing for these power plants, and which the plant owners must budget and charge for, because their revenues are directly related to uninterrupted deliveries. As a result, the capital costs were increased somewhat (i.e., from \$250 to \$310/kW for gas turbines, and from \$450 to \$510/kW for CCGT), and the O&M costs were increased substantially, as you have noted.

While some of the O&M costs could have been put into fixed costs rather than variable costs (practices differ between firms), they would need to be accounted for one way or another and the approach we adopted was to reflect them in variable cost. Hence the variable and fixed costs in our analysis may appear higher and lower, respectively, than what one may see in some other analyses. The net results should be very close. We would also point out that US\$0.002 of every kWh is charged in variable cost for generation-associated transmission, because the energy needs to get from the power-house wall into the grid and often grid strengthening is required as time goes on to accommodate more and more of these plants. (For NT2, the associated transmission charge is US\$0.006 because of the high voltage and long-length of that particular line).

To summarize, (i) the candidate capital and operating costs for the least-cost analysis are those reported in Table 13; (ii) the fuel costs adopted are those reported in Table 14 (with the 2014 value held constant thereafter, as noted above); and (iii) the NT2 costs used are reported in Table 17 of the Final RELC report. These tables report the assumptions adopted for the least-cost analysis.

3. On the Valuation of Firm Power from Theun Hinboun:

The explanation we provided in our letter dated March 30, 2005 is complete and technically correct. In our view, it would be incorrect to reduce benefits for capacity since capacity is not reduced or lost. Only energy will be lost, and that energy is correctly valued at its incremental replacement cost. Your statement that the THB deduction is new is incorrect: it has been included in all of our work in 2004 and 2005.

4. Similarities and differences of the final results of the least-cost analysis:

It is not surprising that the drop in net benefits is small (0.06%, six-hundredths of one percent) when measured as a percentage of total system expansion and operating costs. First, the economic cost of the NT2 project only increased by about US\$16 million (US\$1005 million in early 2005 compared to US\$989 million in mid 2004). Second, NT2 operating costs increased because we deducted the carbon credit that had previously reduced operating costs. Third, the PV of the net savings attributable to NT2 during the "planning period" (pre-2015 when NT2 is constructed) declined by PV US\$7 million. These savings declined by less than the NT2 project cost increase because the capital and operating costs of the natural-gas based alternatives increased. The real issue is why the PV savings in the end-effects period (2015 onward) are higher in the 2005 results than in the 2004 results. The end-effects period is important to the aggregate result because even though its annual contribution to present value declines year by year, the duration of the end-

effects period is long in comparison with the planning period. The end-effects period calculates the comparative capital and operating costs between NT2 and the alternative non-NT2 capacity in which these costs for gas turbines are higher in the 2005 report than in the 2004 report, for the reasons explained.

As mentioned on pages 30 and 90 of RELC the end-effects period uses the fuel values shown for 2014. As to why the total end-effects period present value is 14% higher in the Final RELC than it was in the Interim Summary Report of mid-2004, the difference is due to a combination of factors, including: (i) substantially higher oil prices for non-gas thermal capacity; (ii) increased capital costs; and (iii) the higher operating cost assumptions for gas turbine/CCGT capacity noted above.

5. On the Capital Cost of Gas Turbines:

The correct values are US\$310/kW for gas turbine capacity and US\$510/kW for CCGT capacity. The text of RELC was not changed as it should have been; the tables in the report are correct as noted above. We will issue an erratum regarding the quotation of US\$250 and US\$450 per kW in the RELC.

6. Accounting for Additional DSM:

Contrary to the assertion on page 3 of your letter, the Bank's due diligence does not reduce the additionally identified DSM/EE potential to zero, but considers it appropriate to incorporate this volume in the risk analysis. We fully understand the methodology that Dr. du Pont used in coming to his assessment of achievable incremental DSM. It includes a large element of personal judgment, because in this area there is no iron-clad, reliable methodology for predicting outcomes, given the factors we have previously explained. Our judgment is that regardless of how these results were estimated, the risk of non-achievement increases or the probability of achievement decreases – however one may wish to look at it – once one gets into estimates that are 227% higher than those already included in the analysis and considerably higher than anything that has actually been achieved to date. We have acknowledged, however, that even if all of these savings were to occur, it could delay the optimal timing of NT2 by about a year, all else equal. A one-year period of premature commissioning would reduce but not eliminate the long-term least-cost advantage of the NT2 project and have a moderate impact on the ERR, as previously explained.

As for the renewable energy component, only firm capacity that is economically superior to NT2 needs to be accounted for the purpose of the economic analysis. Capacity that requires programming and subsidies is generally - by definition - uneconomic, and this is, after all, an economic analysis. Rational decision-makers will insure priority in their capacity expansion programs for economic capacity. In this regard, we note that EGAT's obligation is to provide 5 percent of incremental capacity as renewables over the next six years, not the eight percent which you cite as being under consideration. This amount is not far removed from the estimate for firm economic renewables capacity in the du Pont report (274 MW). This amount constitutes less than a third of NT2 capacity.

7. Committed Upgrades and Plant retirements:

We are very well aware of the issues here and have held extensive discussions with the industry to fully understand the basis of changes in planning decisions from year to year. As we have mentioned, EGAT has some flexibility to adjust retirement dates, up-grade decisions and new

April 8, 2005

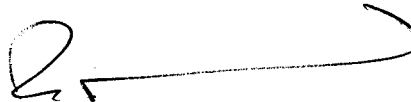
plant procurements depending on the evolution of the demand outlook. Given the amount of incremental capacity the company will need over the next five to seven years and the various stages of planned commitments for individual facilities, we do not perceive a substantial risk of long-term excess capacity on the EGAT system. In fact, there may well be a challenge to meet the load reliably.

The RELC does not include a committed Songkhla CCGT because it was not committed as part of the PDP2003 capacity base; however the Base Case PROSCREEN analysis adds equivalent CCGT capacity based on generic candidate costs. Were this plant to be included, it would reduce both the with and without NT2 Base Case additions by 700 MW; in other words, there would be no effect on the net benefits of NT2. (Note that Khanom thermal is retired as per contract, highlighting the need for capacity additions in the South.)

Excepting plants retired for environmental reasons or by contractual agreement, plants identified as "retired" in the Final RELC report are also included as candidates for repowering (i.e., life extension). These include South Bangkok (units 3-5, 3x310 MW) and Bang Pakong (unit 1, 550 MW). Note that all four of these candidates are included in the economic and commercial Base Case, both with and without NT2.

We sincerely hope that this addresses your remaining issues.

Sincerely,

A handwritten signature in black ink, appearing to be 'Ian C. Porter', with a long horizontal stroke extending to the right.

Ian C. Porter
Country Director, Lao PDR and Thailand
East Asia and Pacific Region

315/247 Sathupradit 19
Bangkok, Thailand 10120

Mr. Ian C. Porter
World Bank Country Director
Lao PDR and Thailand
East Asia and Pacific Region

Dear Mr. Ian C. Porter,

Re: flawed assumptions and false statements in NT2 economic appraisal

Thank you for your letter dated 8 April.¹ It helps resolve one issue (apparent post-2014 natural gas price increase), and helps clarify others. Most of your answers reinforce our concerns that key assumptions used in the *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Final Report*² (RELC) and the *Lao PDR Nam Theun 2 Hydroelectric Project: Project Economic Analysis*³ are flawed in ways that strongly favor a positive appraisal of NT2.

We have calculated⁴ the contribution of the *RELC*'s erroneous assumptions towards the *RELC*'s claimed present value US\$188 million economic "savings" in the "with NT2" scenario (Table 1). Including only the flaws whose impacts we were able to calculate, and using techniques that understate the economic contributions of the erroneous assumptions, we estimate that these errors in the *RELC* account for at least present value US\$220 million of the "with NT2" scenario's claimed present value US\$188 million savings. We are concerned that correcting the economic appraisal may show that the project is not economically least-cost. The key problematic assumptions we have identified are summarized below in Table 1. The remainder of this letter discusses in greater detail the erroneous assumptions and other problematic aspects of the economic appraisal of NT2.

¹ All correspondence in this dialogue (now 5 letters) is available at <http://www.palangthai.org/docs/RemarkableAssumptions.pdf>

² Robert Vernstrom, 2005. *Nam Theun 2 Hydro Power Project Regional Economic Least-Cost Analysis: Final Report*. March. url: <http://siteresources.worldbank.org/INTLAOPRD/Resources/RELC-2005-final.pdf>. In earlier letters we referred to this report as *Final*. In this letter we adopt the Bank's abbreviation of *RELC*. Similarly, we adopt the Bank's abbreviation of *Nam Theun 2 Hydro Power Project Regional Economic Least Cost Analysis: Draft Final Report* as *RELC/2004*. Previously we had referred to this as *Draft Final*.

³ World Bank, 2005. *Lao PDR Nam Theun 2 Hydroelectric Project: Project Economic Analysis*, March 14. url: http://siteresources.worldbank.org/INTLAOPRD/Resources/Annex_11A.pdf

⁴ The spreadsheet containing these calculations can be downloaded from our website at: www.palangthai.org/docs/NT2EconMalfeas.xls

Description of assumption erroneous assumption / false claim	Contribution towards “\$188 million savings” in “with NT2” scenario.	Notes
Inflation of variable O&M costs for natural gas CCGT and GT in final <i>RELC</i> (released just 1 week before World Bank approval of NT2)	US\$150 million to US\$156 million	CCGT inflated 1240% GT inflated 1000%. Final O&M values far in excess of international benchmarks. Inflation is discernable only in small changes between the <i>RELC</i> and <i>RELC/2004</i> versions of tables printed in 6- or 5.5- point font.
Unfair unequal valuation of loss of firm Theun Hinboun electricity generation caused by NT2 water diversion	US\$51 million to US\$63 million	NT2 power valued at Thai consumer “willingness to pay” of US cents 7/kWh. Theun Hinboun electricity is indistinguishable from NT2 to Thai consumers, but valued at less than one third this amount.
Findings of Bank-commissioned NT2 study on economically superior alternatives are 100% omitted from NT2 economic appraisal calculations.	Difficult to calculate without appraisal spreadsheets. Omitted DSM would delay optimal commissioning 9 months and reduce of ERR from 16.3% to 14.6%.	Additional 1225 MW DSM and 216 MW renewable energy are less costly than NT2. 4000+ MW cogeneration also ignored
Omission of 4 committed EGAT CCGT power plants totaling 2800 MW	US\$19.5 million (Economic impact from omission of just Songkla (700 MW) which has been approved by Cabinet.	These omissions falsely provide flexibility that the <i>RELC</i> relies upon to minimize economic losses from over-capacity due to NT2 in “low demand” scenarios. Omission discernable only through comparison with actual EGAT PDP2003.
Total	US\$220 million to US\$236 million	Exceeds \$188 million savings in “with NT2” scenario
False claims that risk analysis considers only “downside risks” to NT2.	US\$51 million (not included in total ⁵ above)	<i>RELC</i> repeatedly claims that “low construction cost” scenario is excluded from risk analysis. <i>RELC</i> Tables S-1 & 24 show these claims to be false.

Table 1: Summary of key erroneous assumptions in the *RELC* and their contribution towards the Bank’s positive economic appraisal of NT2.

⁵ Not included in total because this is a case of misrepresentation of study methodology rather than an erroneous assumption *per se*.

1. Escalation of O&M costs for CCGT and GT

In the *RELC* variable operations and maintenance (VOM) costs for combined cycle gas turbines (CCGT) and gas turbines (GT) increased 1240% and 1000%, respectively, over the values in the *RELC/2004*. The only evidence for this change was minor adjustments in *RELC* Tables 13 (written in 6 point font) and table 15 (written in 5.5 point font).

Table 2 below shows CCGT⁶ VOM and Fixed O&M (FOM) assumptions in the draft *RELC/2004* and final *RELC* versions compared with benchmark CCGT O&M costs from regulatory bodies and utilities in Thailand and other countries. In order to mitigate the comparability problem that groups apportion costs differently to FOM and VOM we normalized each set of figures by calculating the annual O&M costs per kW in the case in which the generator is operated at 80% capacity factor⁷ (typical for CCGT).

⁶ We focus on CCGT because CCGT is determined by the *RELC* to be the most likely economic alternative to NT2 (*RELC*, p 29 & p 31). As noted above, GT O&M costs also escalated radically over *RELC/2004* values

⁷ Using the formula: Total O&M (“\$/kW-yr”) = VOM (“\$/MWh”) * 8760 hours/yr * capacity factor / 1000 (“kW per MW”) + FOM (“\$/kW-yr”). See worksheet “benchmark VOM” in www.palangthai.org/docs/NT2EconMalfeas.xls. There is little sensitivity to changes in capacity factor. Even at capacity factors as low as 30%, *RELC* figures are more than twice the highest benchmark.

CCGT VOM (\$/MWh)	CCGT FOM (\$/kW-yr)	Annual O&M costs (\$/kW-yr)	Country	Notes
7	18	67.06	Thailand	RELC 1/
0.564	16.8	20.75	Thailand	RELC/2004 2/
0.5358	15.96	19.71	Thailand	EGAT 3/
2.55	10.61	28.48	USA (Cal)	CPUC MPR 4/
1.36	13.57	23.10	USA (Cal)	CPUC merchant-owned CCGT 5/
1.36	13.57	23.10	USA (Cal)	CPUC utility-owned CCGT 5/
2	11.00	25.02	USA (Wash)	Puget Sound Energy 6/
1.26	10.25	19.09	Ireland	Ireland Commission for Electricity Regulation 7/
3.14	2.60	24.58	Australia	New South Wales Regulatory Tribunal 8/

1/ RELC Table 13

2/ RELC/2004 Table 13

3/ EGAT assumptions used in *Strategist* expansion planning modeling. *Strategist* is the updated version of *Proscreen II* software used in the RELC modeling. Price Waterhouse Coopers (2004). Thailand: Electricity Power Tariff Energy Planning and Policy Office -- Inception Report -- Annexes C, table C.6.-E. Bangkok, Thailand.

4/ CPUC CCGT avoided cost. California Public Utilities Commission (CPUC) Electric Avoided Cost Calculation, ver. 21. Prepared by E3, Inc. for the California Public Utilities Commission. 2005. Avoided cost spreadsheet available at: http://www.ethree.com/cpuc_avoidedcosts.html. Assumptions based on *Revised 2004 Market Price Referent (MPR) Staff Report*, February 10, 2005.

5/ CPUC Electric Avoided Cost Calculation, ver. 21, Prepared by E3, Inc. for the California Public Utilities Commission. 2005. Avoided cost spreadsheet available at: http://www.ethree.com/cpuc_avoidedcosts.html.

6/ Navigant Consulting. 2003. LCP Conservation Integration Results, Methodology, & Assumptions. Prepared for Puget Sound Energy. 31 July. Page 22. http://www.pse.com/account/pdfs/lcp_2003_08_29_appendix_b_lcp_conservation_presentation.pdf.

7/ Ireland Commission for Electricity Regulation (1999). Best New Entrant Pricing: A Consultation Paper. Url: <http://history.cer.ie/cer9908i.pdf>. 1999 exchange rates to US\$: <http://www.eh.net/hmit/exchangerates/>

8/ Intelligent Energy Systems (2004). The Long Run Marginal Cost of Electricity Generation in New South Wales: A Report to the Independent Pricing and Regulatory Tribunal. http://www.ipart.nsw.gov.au/documents/Pubvers_Rev_Reg_Ret_IES010304.pdf. Exchange rate of \$Aus = 0.7839 \$US from <http://www.ssga.com/library/povw/lawrencedrydenausdollarin200420050218/page.html>

Table 2: comparison of O&M costs for CCGT between RELC values and international benchmarks.

Perhaps the most startling feature in Table 2 (graphed in Figure 1) is that the RELC O&M values are by far the highest values in the table. Though we conducted an extensive internet search of CCGT O&M costs, *we were unable to find O&M costs anywhere in the world that were even half as high as those assumed in the RELC*. To the best of our knowledge, these cost estimates all include insurance, inspection and maintenance. In addition, the international benchmark values are generally *commercial* O&M costs, and therefore overstate *economic* costs because they do not include profits or taxes. They cover the spectrum from utility-owned generation to independent power producers. In our international search, the highest assumptions we encountered (besides the RELC figures) were those used in avoided cost calculations by the California Public Utilities Commission (CPUC). Consider that California has extremely high labor costs and some of the strictest environmental regulations for power plant emissions in the world. We are surprised that the Bank believes that O&M costs for CCGT in Thailand, which has fairly low labor costs, would be more than twice as high as CPUC cost estimates.

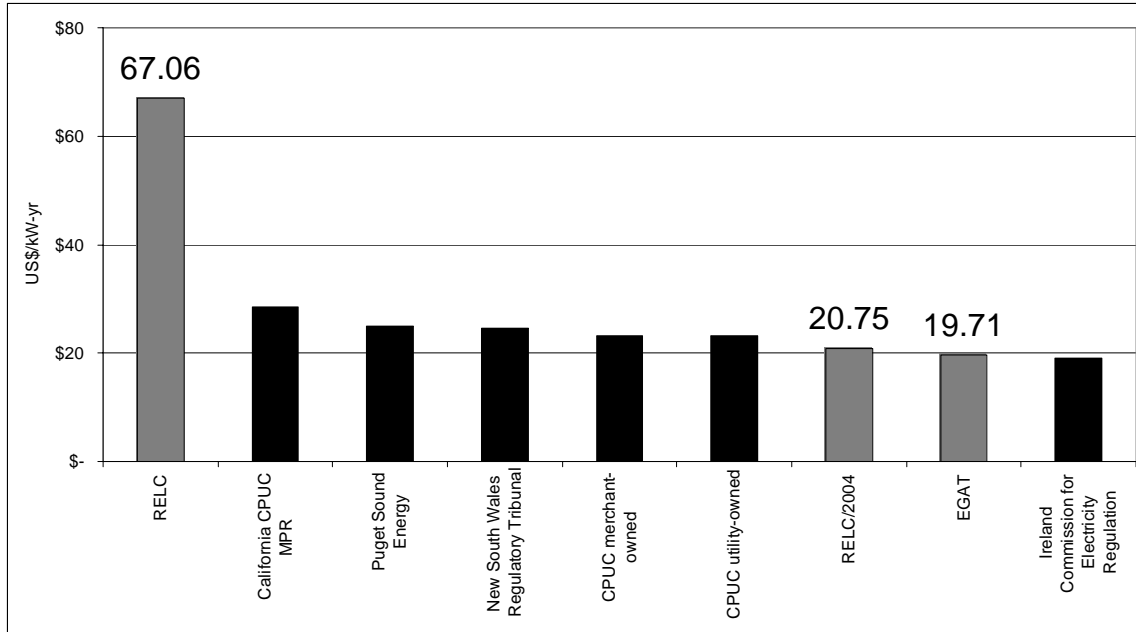


Figure 1: RELC assumptions for annual CCGT O&M costs compared with Thai and international benchmark values. (Graph of data in Table 2). Notice that RELC/2004 costs were similar to Thai and international benchmark figures, but RELC costs are more than twice as high as the highest benchmark.

Perhaps more important than the international benchmark values are the Thai EGAT values. The RELC cost estimates for total O&M are 340% as large as EGAT total O&M cost estimates. EGAT has an extensive record running CCGT in Thailand. For new EGAT plants, it seems appropriate to use EGAT O&M costs.⁸ At the same time, one would not expect EGAT costs for CCGT O&M in Thailand to be *that* different from private sector costs. EGAT typically has a larger workforce per plant than private sector Independent Power Producers (IPPs), but IPPs may pay somewhat higher salaries -- these two effects would tend to compensate for each other. Our research finds evidence that insurance costs for utility and IPP CCGT are similar and account for a fraction of total O&M costs.⁹

What can possibly explain the huge differences between RELC assumptions and benchmark O&M figures?

⁸ Historically it has been government policy that 50% of new generation is built by EGAT. Cabinet has approved the EGAT Sonkla CCGT project. These contradict the RELC presumption that “all future capacity will be developed by the private sector.” (RELC, page 59).

⁹ See, for example, CPUC Electric Avoided Cost Calculation. ver. 21, Prepared by E3, Inc. for the California Public Utilities Commission. 2005. http://www.ethree.com/cpuc_avoidedcosts.html. IPPs and utilities insurance is estimated to be equal at US\$9.24/kW-yr, out of a total of US\$23.10/kW-yr O&M costs.

In response to our inquiry about the escalation of CCGT VOM in the economic appraisal, you claimed in your 8 April letter that “US\$0.002 of every kWh is charged in variable cost for generation associated transmission”.

There is no mention of this figure anywhere in the *RELC* or *Project Economic Analysis* reports. What are the details of the basis for this charge? Thailand’s extensive natural gas pipe network provides considerable flexibility in locating CCGT close to load centers – at least much closer than the Lao border is to load centers. If costs for reinforcing the Thai 500 kV transmission system for CCGT are included in CCGT VOM, it would only be fair to require that these costs be included for NT2 as well. But the *RELC* reports that these are excluded for NT2 (*RELC*, footnote 47, page 59).

Strangely, distributed cogeneration (which has very low – or often negative -- associated transmission costs) was excluded from the terms of reference of the study on alternatives to NT2. This is discussed later on in this letter in our response concerning DSM and renewable energy.

Even if the US\$0.002/kWh transmission charge for CCGT and GT is legitimate (which remains to be proven), it only explains US\$14.02/kW-yr of the *RELC* US\$67.06/kW-yr CCGT O&M costs in Table 2 above. *We note that even after subtracting \$0.002/kWh, RELC values for CCGT O&M costs are still 186% of the value of the highest international benchmark values we encountered in our search, and 269% of the value of EGAT O&M costs.*

Given these irregularities, we respectfully ask that you provide:

1. A detailed justification for the exceptionally high economic cost estimates for O&M of CCGT. Given the importance of this variable, and the radical escalation of its value in the *RELC* it deserves more than the 6-point font footnote to Table 13. Specifically, the justification should include a discussion of the conditions in Thailand that lead to O&M CCGT costs that are far above international levels and published EGAT figures.
2. An explanation of why published EGAT figures are not relevant for the *RELC* analysis.
3. An explanation for why there was no discussion in the text of the *RELC* of the 1240% escalation in CCGT and 1000% escalation in GT VOM values. We find this omission astounding considering that this change accounts for more than half of the “with NT2” savings and that the values assumed are exceptionally high by international standards.

The domestic (EGAT) and international benchmark values and the discussion above suggest that the *RELC/2004* values for natural gas O&M are more realistic than the more recent *RELC* figures. We calculate¹⁰ that inflating CCGT and GT VOM costs from the

¹⁰ www.palangthai.org/docs/NT2EconMalfeas.xls, worksheet “Inflated gas VOM”

RELC/2004 values to the *RELC* values accounts for present value US\$150 to \$156 million of the *RELC*'s "with NT2" economic savings of US\$188 million.

Because these *RELC* O&M assumptions in question are apparently also used in the commercial analysis, our calculations hold for this case as well. That is, US\$150 to US\$156 million of the *RELC*'s "with NT2" commercial savings of US\$145 million are attributable to the *RELC* escalation in CCGT and GT O&M costs.

2. Irregularities in transmission cost assumptions

In response to our inquiry about the escalation of CCGT VOM in the *RELC*, you stated that "for NT2, the associated transmission charge is US\$0.006 [per kWh] because of the high voltage and long length of that particular line." (8 April, 2005)

Can you help us understand this \$/kWh transmission cost figure better? We find it difficult to reconcile your US\$0.006/kWh NT2 transmission claim with what is published in the *RELC*.

There is no mention of "\$0.006/kWh" NT2-associated transmission costs anywhere in the chapters related to the economic appraisal in the *RELC* or the *Project Economic Analysis*. The only relevant figure we can find in the *RELC*'s economic assessment is that the total NT2-associated transmission costs are estimated to be (present value) US\$82.4 million (*RELC*, page 44, Table 17)¹¹. Taking the *RELC*'s assumptions about discount rate and NT2 annual energy production, present value US\$82.4 million is equivalent¹² to a transmission charge of \$0.00314/kWh, a little bit more than half of the \$0.006/kWh you claim in your letter.

It is only *RELC Chapter 6: Commercial Assessment* that mentions something that looks like the "US\$0.006/kWh" cost you cite. However, it does so in such a way that we can only conclude that this cost was *not included* in the *RELC*'s economic assessment, but was added in the transition from economic assessment to commercial assessment:

"In the commercial analysis... the cost of each kWh is increased by US\$0.00615, the estimated levelized cost of incremental transmission investments required to deliver all planned Lao hydro purchases from the Thai border to the nearest 500 kV line (for transmission to the Bangkok metropolitan area)" (*RELC* page 59)

¹¹ There is no detailed breakdown of what this US\$82.4 million comprises. Correct practice would be to compute and state the incremental transmission costs for the pure NT2 addition, including the towers, wire, telecommunications, protection, substations, special equipment (series or shunt compensation), changes to SCADA/AGC databases and displays, commissioning costs, project management, and the present value of the associated O&M costs for the line. Without these details it is difficult to determine whether or not *RELC*'s figure of \$82.4 million is reasonable.

¹² See worksheet "levelized NT2 econ trans" in www.palangthai.org/docs/NT2EconMalfeas.xls

We are concerned that *even* the \$0.006/kWh *commercial* transmission cost figure may be considerably underestimated. The *RELC* terms of reference explicitly instructs study authors that, “The project-associated incremental transmission costs for Thailand need to be determined ... on a basis that does not include any other future hydro exports from Laos to Thailand, because of their uncertainty.” (*RELC*, page 74) But the *RELC* appears to have violated the TOR by sharing the commercial cost of NT2-associated transmission with thousands of MW of Lao hydropower that does not exist: “the levelized cost is based on transmitting 3,300 MW from agreed border crossing points to Tha Tako (near Nakhorn Sawan), the closest 500 kV connection point.” (*RELC* footnote 47, page 59). NT2 accounts for 920 MW¹³ of this 3,300 MW, but where do the remaining 2,380 MW come from?

Why did the commercial assessment of transmission costs fail to follow the directive specified in the TOR? Clearly the levelized commercial transmission costs would be substantially higher than \$0.006/kWh if they were not able to share transmission resources with phantom Lao hydropower plants.

Moreover, we remain puzzled how to reconcile a corrected estimate of commercial transmission costs with the US\$0.00314/kWh economic costs discussed above.

Considering these apparent irregularities, and the questions raised above regarding CCGT transmission cost assumptions, can you provide us with a clear explanation of how transmission costs for CCGT and NT2 are accounted for in the *RELC* economic appraisal, how they are different in the *RELC* commercial analysis, and how they comply with directives specified in the TOR? A key component of this would be a transmission plan showing what line(s) are to be built, and a breakdown of economic and commercial transmission costs.

3. Regarding the valuation of Firm Power from Theun Hinboun

In our previous letters we noted that water used to produce electricity at NT2 will cause the Theun Hinboun (THB) dam 40 kilometers downstream to lose a significant amount of energy production. The World Bank NT2 economic appraisal values NT2’s firm energy at US cents 7 per kWh¹⁴ but values Theun Hinboun’s loss of (firm) electricity at less than one third this amount (2.3 cents per kWh)¹⁵.

First and foremost, this assumption defies the basic economic concept that perfect substitute goods have equal economic value. Valuation of NT2’s firm electricity is based on Thai consumer’s willingness to pay (*Project Economic Analysis*, page 20). To Thai consumers, a unit of firm electricity from THB is indistinguishable from a unit of firm

¹³ NT2 is considered a 995 MW plant, comprising 920 MW to Thailand and 75 MW to Laos. See *RELC* footnote 8, page 9.

¹⁴ *Lao PDR Nam Theun 2 Hydroelectric Project: Project Economic Analysis*, March 14. Page 20.
http://siteresources.worldbank.org/INTLAOPRD/Resources/Annex_11A.pdf

¹⁵ *Project Economic Analysis*, page 22.

electricity from NT2. We do not mean this merely in the broad sense that no one can tell exactly where their electricity comes from. But rather in the very rigorous sense that electricity from Theun Hinboun and Nam Theun 2 are as close to perfect substitutes as any energy economist could hope for. Firm electricity from THB and NT2 share the following properties: (a) both are sold under “firm” contract to deliver power at guaranteed times and quantities at the times when Thai consumers need it most; (b) both are derived from hydropower from neighboring locations in Laos and therefore subject to the same risks in terms of droughts, political risk, and other contingencies and (c) both have essentially identical impact on the Thai transmission system. Since electricity from these two sources are perfect substitutes, we must assign them the same value.

However, your prior letters to us indicate that you believe it more appropriate to frame the valuation of THB electricity loss in terms of capacity (kW) and energy (kWh) components that make up commercial firm energy contracts. You argue that the water diversion leads to “no reduction” in capacity (kW) at Theun Hinboun, and therefore Theun Hinboun is correctly valued by considering only the incremental cost of replacing the lost energy (kWh).

We think this “capacity/energy” framing is arbitrary and inconsistent given the identical characteristics of the two goods discussed above and the economic principle of equal value for perfect substitutes. But even framed this way, the assertion that capacity from THB “is not reduced or lost” as a result of water diversion from NT2 is unfounded.¹⁶ If it were true that water diversion from THB to NT2 results in no capacity loss, one could in theory divert 100% of the water from THB until all that was left of this “firm” project is a dam and a dry reservoir. THB would still have “no reduction in capacity” in the sense that its generators would retain their original nameplate capacity. But this capacity would be worthless from the utility’s perspective without adequate water to power the turbines. In order to justify the claim of “no reduction in capacity” one must show (using engineering and hydrology studies) that the water diversion in question in no way affects the capacity Theun Hinboun to generate power -- even in drought years -- at times, in quantities and durations that it was able to generate before NT2.

Another argument posited in your 30 March letter in defense of unequal valuation of THB firm power is the claim that “the Theun Hinboun project was predicated on the knowledge that the NT2 project – once constructed – would draw water from THB, which has used the incremental water available as a result of the delayed implementation of NT2 to generate additional power for export to Thailand.” This argument turns appropriation water rights conventions upside-down by essentially arguing that historic users of water have fewer rights than do newcomers. Regardless, it is a grossly insufficient basis for valuing THB power at distress prices. From an economic perspective, what matters is the technical capacity of Theun Hinboun to generate benefits to society, not some claim that a project was predicated on a particular expectation.

¹⁶ Your letter to us, 8 March. www.palangthai.org/docs/RemarkableAssumptions.pdf

Indeed, if the claim is correct that Theun Hinboun's construction was predicated on the expectation water diversions to NT2, then in a "without NT2" scenario Theun Hinboun may have options available to expand dam crest height or turbine capacity to fully exploit the available water flows. These options would obviously be precluded with construction of NT2. This option value should have been counted against NT2's economic "savings".

We calculate that the Bank's misvaluation of power from Theun Hinboun is worth present value US\$51 to US\$63 million of NT2's calculated present value US\$188 million economic "savings".

4. Accounting for Additional DSM/RE

Your April 8 letter states that Dr. Peter Du Pont's Bank-commissioned assessment of DSM/RE is incorporated in the *RELC* risk analysis. How is this possible when the risk analysis numbers were not changed between the *RELC/2004* (released before the DSM/RE impact study) and the final *RELC* report?

Let us review when each study was released and what each said with respect to DSM potential and demand forecast scenarios.

June 2004: The *RELC/2004* is released. The forecast of electricity demand used in the risk assessment (Table 9, page 22) concludes that demand in the base case will rise to 38,590 MW by 2016. In a high case the 2016 peak load is forecast at 53,652 MW, and in a low case forecast at 26,280 MW. The DSM assumption that informed this assessment is 982 MW of DSM by 2011 as projected in the Thai Load Forecast Subcommittee (TLFS) August 2002 load forecast (see Table 3, page 16).

24 March 2005: The World Bank releases Dr. Du Pont's study, *Nam Theun 2 Hydropower Project (NT2): Impact of Energy Conservation, DSM and Renewable Energy on EGAT's Power Development Plan (PDP)*¹⁷. The study heavily discounts both commercial DSM potential and government programs to conclude that 1,225 MW of additional DSM and 274 MW of renewable energy are achievable by 2011 and are economically and commercially lower cost than electricity from NT2.

24 March 2005: The *RELC* is released. Its risk assessment of electricity demand (also Table 9, page 24) is figure-for-figure 100% identical to the *RELC/2004* version of Table 9. The DSM assumption that informs this assessment is *still* 982 MW (Table 3, page 18).

If Dr. Du Pont's findings were included in the risk analysis, then Table 3 of *RELC* would show 2207 MW of DSM by 2011, not 982 MW. Table 9 base-case figures in the *RELC* would therefore be shifted 1225 MW downward by year 2011. Following the report's methodology regarding demand scenarios, these revised base-case figures would then be subject to the +/- 25% variation in the high and low demand cases.

¹⁷ du Pont, P. (2005). *Nam Theun 2 Hydropower Project (NT2) Impact of Energy Conservation, DSM, and Renewable Energy Generation on EGAT's Power Development Plan*. Bangkok, World Bank. 24 March. <http://siteresources.worldbank.org/INTLAOPRD/Resources/DSMmarch2005.pdf>

Without the spreadsheets used by the *RELC* author, and without re-running the economic models it is difficult to calculate the economic impact of the DSM omission, but it is certainly significant. Your own analysis indicates that including omitted DSM reduces the base case ERR from 16.3% to 14.6%¹⁸.

Regarding the treatment of renewable energy in the *RELC*, there is a similar failure to incorporate Dr. Du Pont's findings. The treatment of renewable energy in the *RELC/2004* and the Final *RELC*'s treatment are word-for-word identical. Each version of the study includes 197 MW of Small Power Producer (SPP) renewable energy as committed plant additions (*RELC* page 27), dispatched without regard to cost (*RELC* p. 36). Contrary to your assertion that "only firm capacity that is economically superior to NT2 needs to be accounted for the purpose of the economic analysis", there no was requirement in either the *RELC/2004* or the *RELC* that this renewable energy generation had to be less costly than NT2, it was simply part of the 2003 EGAT PDP. The inclusion of these plants reflects EGAT's expectation that these plants will be coming on-line because they were approved as of March 2003 under the Thai government's subsidized renewable energy SPP program (*RELC*, page 26).

The 274 MW of commercially and economically superior (to NT2) renewable energy in Dr. du Pont's study included 216 MW of biogas-based electricity which is clearly *additional* because it is expected to come online under the (unsubsidized) VSPP program, not the SPP program. Together with the 1225 MW of additional DSM discussed above, this accounts for 1441 MW of clean energy identified by a World-Bank commissioned study as economically and commercially superior to NT2, that was omitted from the NT2 economic appraisal.

The discussion of renewable energy in the *Project Economic Analysis* largely ignores the analysis of Dr. Peter du Pont's study, and essentially dismisses all renewable energy as too expensive. The section on biomass is particularly striking: "Based on discussion with EGAT the biomass potential that can be supported from the annual availability of raw material is about 700 MW... and the generating cost is about THB 3/kWh (over US cents 7/kWh, based on an EGAT pilot project.)"¹⁹ However, the author's source at EGAT failed to recognize that there is already 861 MW (capacity) of biomass generators online as SPP generators. 32 out of 41 of these are non-subsidized, and the vast majority sell power at 1.77 baht/kWh (US Cents 4.425/kWh)²⁰. Dr. du Pont's study includes a comprehensive review of a number of government-commissioned studies of renewable energy potential, as well as interviews with industry experts, and concludes that about 2400 MW of additional biomass are commercially viable. The Thai Ministry of Energy estimates biomass electricity generation potential in Thailand, based on availability of

¹⁸ Your letter to us, 30 March 2005, page 3.

¹⁹ *Project Economic Analysis*, page 8

²⁰ du Pont *NT2 Impact of DSM/RE*, page 34.

raw material, at 7000 MW; an order of magnitude higher than the estimate provided by the author's EGAT informant.²¹

The reason these existing biomass generators can be viable at such low tariffs is that they are generally built as cogeneration (combined heat and power) installations, which vastly increases overall efficiency and provides valuable steam to industry.

An even more significant omission is the unfortunate fact that consideration of fossil-fuel fired cogeneration was not included in the Terms of Reference (TOR) of the *DSM/RE* study (and were also excluded/ignored as least-cost competitors in the *RELC* and *Project Economic Assessment*). Notwithstanding the omission from the TOR, Dr. Peter Du Pont noted the following in his study:

“This study has also not considered energy savings from cogeneration — although this may be a considerable omission. Cogeneration is a large source of potential energy efficiency savings because the combined production and utilization of heat and power for industrial processes can raise the efficiency of the power plant output by as much as two-fold and reduce the need for electricity supply. The SPPs noted in Table 40 that have been submitted but not contracted by EGAT represent more than 4,000 MW of power, approximately half of which would be consumed on site and half sold to the grid. Since most of these projects were submitted prior to the economic crisis, it is likely that there is significant additional cogeneration potential for on-site generation as well as sale to the grid. While this report did not investigate the cogeneration potential in detail, it is noted that the number of submitted projects represents a large, as yet untapped, resource.” (*NT2 Impact of DSM/RE*, page 55)

Clearly, the results of Dr. Dupont's DSM/RE study are the tip of the iceberg of available true economic least-cost alternatives.

Contrary to your claims, we never asserted that EGAT was obligated to provide 8 percent of *incremental capacity* as renewable energy. We wrote (page 3, 31 March) that Thailand has adopted a target of 8% of *total (commercial) energy* come from renewable energy by year 2011. This target is one of the pillars of Thailand's current energy strategy. The strategy (and the 8% policy) are clearly discussed, in English, in one of Thailand's key energy policy documents: “Energy Strategy: Energy for Thailand's Competitiveness”. The document was released at 28 August 2003 at a workshop held by the Ministry of Energy, and presided over by Prime Minister Thaksin Shinawatra. It is available online from the website of the Thai Energy Planning and Policy Office (EPPO).²² If you are not aware of this key energy sector document, as your response to our letter seems to

²¹ Thai Ministry of Energy. (2003). “*Renewable Energy: New Opportunities for Thailand*”. (Thai language). Presented at the Energy Strategy for Competitiveness workshop. 28 August 2003. <http://www.eppo.go.th/admin/moe-workshop1/energystrat2.zip>

²² See: <http://www.eppo.go.th/doc/strategy2546/strategy.html>

indicate, then this is both tragic and astonishing given the role of the World Bank in energy in Thailand.

As discussed in Dr. Du Pont's study there are a number of policies that will be used to achieve this 8% target, including (but not limited to) the EGAT's 5% renewable portfolio standard. Other key measures for electricity include feed-in tariffs, capacity subsidies, and tax reductions. In addition, significant measures are planned for transportation and industrial heating. We note that the government has allocated US\$412 million to meet the 8% target.

Finally, you state that "capacity that requires programming and subsidies is generally – by definition – uneconomic, and this is, after all, an economic analysis." We wonder how you consider NT2 in light of this comment. Do not the World Bank political risk guarantees and grants valued at up to US\$270 million for NT2 constitute a subsidy?

5. Omission of Committed Plants and Overestimation of Plant Retirements

In our previous letter we explained that the April 2003 version of the *Power Development Plan (PDP)* upon which the NT2 economic appraisal is based was never approved by the Thai government. The official *2004 PDP*, which calls for 4,098 MW more capacity additions than NT2 version, provides a much more realistic basis for assessing Thailand's power plant investment decisions. The *2004 PDP* was issued in August 2004 – plenty of time for inclusion in the *RELC* (released in March 2005). We are still awaiting an explanation of why the *RELC* ignored an officially approved PDP in its "revisitation of all major assumptions".

But, as we have pointed out before, the *RELC* does not follow even the *April 2003 PDP* that it purports to follow. The *RELC* omits, without explanation, plants that are clearly identified in the *April 2003 PDP*²³. These plants comprise Songkla CCGT²⁴ (700 MW, to be commissioned in 2008), North Bangkok CCGT (700 MW commission 2009), South Bangkok CCGT (700 MW, commission 2009) and Bang Pakong CCGT (700 MW, commission 2010). These omissions are beneficial to a positive economic appraisal of NT2 because they open up (false) demand for new generation that NT2 conveniently fills.

We have spoken with a number of planners at EGAT who assure us that EGAT considers all of four of these plants "committed", not "candidates". The Songkla plant has been approved by the Thai Cabinet, and construction is scheduled to start this year and to be completed in 2008.²⁵

You argued in your 8 April letter that "Were [Songkla] to be included, it would reduce both the with and without NT2 Base Case additions by 700 MW; in other words there would be no effect on the net benefits of NT2."

²³ EGAT 2003. Power Development Plan (in Thai). April. p 41.

²⁴ identified in April PDP 2003 as "Southern"

²⁵ Bangkok Post. (2005). "Gas-fired power plant gets cabinet approval" 8 June. Page 5.

This statement is true but of little relevance. The *RELC* positive economic appraisal of \$188 million “savings” from NT2 is a risk-adjusted result. Your study methodology requires you to include a 25% weighted probability of a Low Demand scenario. The relevant question is not “what will the impact be on the Base Case” but obviously, “what will the impact be on the study’s final result – the probability-weighted real cost-risk analysis of the “savings” of the “with NT2” scenario.”

In the event that future demand for electricity in Thailand is low, constructing NT2 would mean that these power plants lie idle for longer than they would if NT2 were not built, accruing costs but not providing benefits. The Bank’s economic appraisal of NT2 considers a scenario in which electricity demand is low, but it fails to include these power plants. Including just one of these “omitted but committed” power plants, Songkla, would reduce overall NT2 economic savings by another US\$20 million.²⁶ The calculations also hold for the commercial assessment: \$20 million of the projected “with NT2” US\$145 million commercial savings is due to omitting Songkla in a low demand scenario.

Similarly, your response regarding the plant retirements is unacceptable. The *RELC* claims to follow the April 2003 PDP, but *RELC* treatment of plant retirements is not consistent with their treatment in this same PDP. The 2003 PDP treats all “plants planned for reconditioning” as “plants planned for reconditioning”, not as “retirements and candidates for reconditioning”. The distinction is important because interpreting the 2003 PDP as the *RELC* does creates false opportunities to retire more plants to make way for NT2 capacity.

Note – the impact of these omissions would increase substantially if the *RELC* did not also ignore the additional achievable DSM and renewable energy discussed above in section 3 of this letter.

6. False claims about analyzing only downside risks

We must also register a complaint concerning false claims in the presentation of the methodology and results of the *Final RELC*. The executive summary states, “It was decided to focus the cost-risk analysis for the current study *only* [emphasis added] on the *downside risks to NT2* [emphasis in original]. Specifically, the analysis was limited to the base case and those cases which could be expected to pose the greatest test to project viability, i.e., conditions of lower than expected demand, lower than expected fuel prices, and *higher than anticipated NT2 capital costs* [emphasis added].” (*RELC*, page iii) The executive summary concludes that “The economic evaluation, based on a probability-weighted real cost-risk analysis of *downside risks* [emphasis added], indicates a real savings... on the order of US\$188 million will accrue to the region over the lifetime of the plant.” (*RELC*, page vii)

²⁶ Calculations and references at: www.palangthai.org/docs/NT2EconMalfeas.xls on the worksheet “Omitted Songkla”

There are five explicit statements that the analysis considers only NT2 capital costs that are base case values or higher than anticipated (*RELC* page iii, page 40, page 48, page 54, page 68). The statements are integrated into the text in a variety of locations and demonstrate rephrasing in different words.²⁷

It is true that the Bank included only base case or “downside risk” scenarios concerning electricity demand and gas prices. But the assertion that capital costs were “base case or higher than expected” is wrong. Table S-1 (*RELC* page v) and Table 24 (*RELC* page 55) clearly shows that the Bank based its risk assessment on the assumption that construction costs could be “low”, yielding an economic windfall for the “with-NT2” scenario. Low construction costs are applied in 9 of the *RELC*'s 27 scenarios, and in each case they lead to \$205 million greater “savings” than base case construction cost scenarios. Because the study methodology assumes that the probability of “low construction cost” occurrence is 25% this means that US\$51.25 million of the US\$188 million “risk adjusted NT2 savings” is attributable to this upside “risk”.

This is particularly relevant when one considers that the assumption of a 25% probability of a “30% lower than expected construction cost” scenario 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.²⁸

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%.²⁹ Specifically regarding construction cost estimates in the economic appraisal of NT2, a 1999 World Commission on Dams draft study notes, “Indeed, it could be argued that 30 percent cost overruns should be the base case and pessimistic scenarios assume even higher cost overruns.”³⁰

²⁷ See for example differences in wording between references to claimed understatement of NT2 benefits due to omission of low construction cost scenarios on *RELC* pages iii, 40, 48 and on pages 54 and 68.

²⁸ 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

²⁹ 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>

³⁰ McKenney, B., M. Manion, et al. (1999). *World Commission on Dams: Thematic Review III.1: Economic and Financial Issues Financial, Economic and Distributional Analysis: Version 1 – Draft*. Page 40. http://www.dams.org/docs/kbase/thematic/drafts/tr31_draft_ver1.pdf

Given the historical record, we think that it is very questionable to have included a windfall “low construction cost” scenario as having a 25% probability of occurrence in the modeling. But it is much worse to have included it in the *RELC* modeling while repeatedly claiming it was excluded.

In a related issue, repeated claims in the *RELC* of “understating NT2 benefits” by leaving the “high demand” scenario out of the modeling are over-advertised. Comparison of “high demand” and “base case demand” scenarios in the *RELC/2004* show limited increased economic savings from NT2 in a high demand scenario. Results from the high demand scenario in the *RELC/2004* show a modest increased savings of US\$22 million over the base case.³¹ This translates into a barely noticeable \$5.5 million increase in the “with NT2” risk-adjusted result. By comparison, the low demand case (even ignoring Songkla and other omitted committed EGAT plants) is very costly for the “with NT2” scenario in the *RELC* and *RELC/2004*. The difference between the *RELC* low demand and base case demand is \$242 million.³² Considering the 25% probability of this scenario in the *RELC* modeling, impact on the *RELC* final result is US\$60 million – eleven times higher than the projected impact of high demand scenario.

This extreme difference between the impact of low and high demand scenarios arises because NT2 is fully utilized in the base case and there is limited opportunity for further benefits due to increased load in the high demand case. In the low demand case, however, NT2 leads to considerable (and costly) excess generation capacity. The *RELC* does admit this, but only once, on page 54. This does little for readers who only get as far as the executive summary, where they are exposed to three statements (page vi footnote 6, page vii footnote 7, and page viii) that proclaim that leaving out the high demand scenarios understates the economic advantage of NT2. At the very least, the author of the *RELC* should have added a caveat in the executive summary that explains that symmetrical inputs in the high and low demand scenarios yield highly asymmetrical outputs, and that high demand scenario NT2 savings are nearly equal to base case numbers.

7. On the cost of natural gas after year 2014

Thank you for clarifying (in your 8 April 2005 letter) the use of the US\$3.65/mmbtu natural gas price in the *RELC* version of the study. Needless to say, a better job could have been done with the treatment of this crucial³³ variable in the text of the report. It was particularly confusing that the value of this variable used in the economic least cost

³¹ Present value US\$299 million savings in high demand case vs. US\$277 million savings in base case demand. *RELC/2004* page 49.

³² See *RELC* page 64. Present value economic savings of \$24 million in low demand case versus \$266 million savings in base case. *RELC* page 49. The difference is even more pronounced in the commercial analysis which concludes that savings “with NT2” are negative would come at a present value \$32 million cost in a low demand scenario, compared with \$266 million savings in the base case scenario.

³³ We calculate that a 61% increase in post-2014 natural gas prices would be worth present value \$148 million to \$153 million of “savings” in a “with NT2” scenario.

analysis is *not* shown in any table in the entire report. Yet a value for the variable *not* used in the economic least cost analysis *is* shown in a table (Table 15) in the Chapter titled “System Supply Assumptions”.

The fact that the values of key variables for natural gas (the capital costs for both CCGT and GT) stated in the text of the final *RELC* were wrong³⁴ further eroded our confidence in the mention in the text of the post-2014 natural gas values on page 90 and the somewhat elliptical mention on page 30.

Conclusions

The *RELC* and *Project Economic Analysis* contain a number of erroneous assumptions and false statements. All in all, our calculations show that the erroneous assumptions contribute at least present value US\$220 million towards the *RELC* calculated present value US\$188 million economic savings in a “with-NT2” scenario.

Erroneous assumptions

- Massive escalation O&M costs for CCGT in Final *RELC* (released just one week prior to Bank approval of NT2)
 - more than double highest international benchmark values
 - no discussion in text
 - discernable only through inspection of tables written in 6-point and 5.5-point font
 - accounts for \$150 to \$156 million of “NT2 savings”
- Unequal valuation of NT2 & Theun Hinboun firm electricity
 - Violates economic principle of equal valuation for identical substitutes
 - No mention of this variable or its value in *RELC*.
 - Accounts for \$51 to \$63 million of “NT2 savings”
- 0% inclusion of results from World Bank-commissioned study on DSM/RE in Final *RELC*
 - Final *RELC* tables showing DSM assumptions and demand assumptions unchanged from *RELC/2004* values even after DSM/RE study finds substantial additional DSM and renewables are achievable at lower cost than NT2.
 - Difficult to assess impact without access to study spreadsheets. World Bank calculates substantial ERR reduction.
- Omission of Committed Plants and Overestimation of Plant Retirements
 - Failure to use PDP approved by government despite official release 7 months before *RELC* submitted
 - Omission of 2800 MW of committed EGAT generation from outdated 2003 *PDP* in NT2 “version” of *PDP*.
 - Omission includes Songkla 700 MW, which has already been approved by Cabinet

³⁴ The text of the Final *RELC* erroneously refers to capital costs of natural gas CCGT and GT at their *RELC/2004* values and never at their escalated *RELC* values. *RELC*, page 28.

- “Omitted committed” Songkla alone accounts for \$19.5 million of risk-adjusted “NT2 savings”. Others would be more.

False statements

- The *RELC* makes multiple claims that economic cost-risk assessment modeling was *limited to consideration of the downside risks to the NT2 project*. Five statements claim that analysis considers only NT2 capital costs that are base case values or “higher than anticipated”. These claims are shown to be false by inspection of Table S-1 and Table 23 (both in 6.5-point font) which show that inclusion of “low construction cost” scenario adds US\$51.25 million to risk-adjusted NT2 economic “savings”.

As we have done from the start, we urge you to consider an independent investigation into the irregularities in the NT2 economic appraisal, and to reconsider the role of the World Bank in the NT2 project. It is not too late to correct these errors and evaluate the project on its true merits. If this results in a cancellation, it is still likely to be better than committing Thai ratepayers to paying for an economically inferior choice. Investors are affected as well, as many of these assumptions strongly inflate the commercial appraisal of the project.

Sincerely,

Christopher E. Greacen, Ph.D.
Director, Palang Thai chris@palangthai.org

Decharut Sukkamnoed, Ph.D. Candidate
Lecturer of Economics, Kasetsart University tonklagroup@yahoo.com

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The World Bank

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July 21, 2005

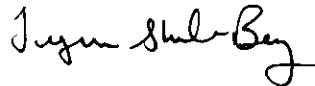
Mr. Christopher E. Greacen, Ph.D.
Director, Palang Thai
315/247 Sathupradit 19
Bangkok, Thailand 10120

Dear Sir,

Subject: World Bank Economic Analysis on the Nam Theun 2 Project

Thank you for your letter dated June 27, 2005 regarding the Nam Theun 2 project economic analysis. We will be responding to you as soon as possible.

Sincerely,



Lynne Sherburne-Benz
Acting Country Director
Lao People's Democratic Republic
East Asia and Pacific Region

cc:

Chalotorn Kansuntisukmongkol, Ph.D.
Lecturer of Economics, Thamassat University

Decharat Sukkamnoed, Ph.D. Candidate,
Lecturer of Economics, Kasetsart University

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October 12, 2005

Mr. Christopher E. Greacen, Ph.D.
Director, Palang Thai
315/247 Sathupradit 19
Bangkok, Thailand 10120

Dear Mr. Greacen,

Subject: Lao PDR: Nam Theun 2 Hydroelectric Project

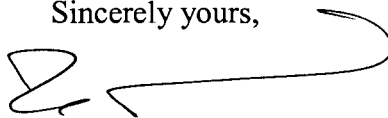
This is further to our interim response of July 21, 2005 to your letter of June 27, 2005.

We appreciate your analysis and the interesting issues you have raised in your letter. We have thoroughly reviewed the issues you raised and the analysis you presented. A summary of our review is attached as an Annex to this letter.

In general, our response parallels the outline of your letter. However, many of the issues that you raised have been addressed in earlier correspondence. In these cases, we have briefly summarized our response, citing a link to previous correspondence on the Bank's NT2 project website.

We hope this response addresses the major issues you have raised.

Sincerely yours,



Ian C. Porter
Country Director, Lao PDR
East Asia and Pacific Region

Technical Response Note on NT2 Economic Analyses

A. O&M Cost Assumptions

We have reviewed the analysis of operations and maintenance (O&M) costs you have carried out. These data are drawn largely from the US and show a fairly narrow range of O&M costs – between 0.27 US cents/kWh and 0.41 cents/kWh. This range is far narrower than the range of O&M costs identified in the Bank’s own investigations. Our analysis, drawn largely from international data, project feasibility studies, and internal Bank studies and reports, demonstrates that O&M costs vary markedly between projects, as summarized in the table in Attachment 1. This table shows a range of total O&M costs from 0.32 US cents/kWh to 0.69 cents/kWh, based on plants in diverse locations in Europe, Asia, the Middle East, Africa and North America. (The table expresses all data, including the data you have provided, in the common numeraire of US cents/kWh, assuming an illustrative 80 percent plant factor for the fixed O&M component.)

You will note that the figure adopted for the RELC analysis – 0.76 US cents/kWh¹ – is slightly above this range and considerably above the value used in RELC/2004. The Bank selected this higher value based on engineering advice that we had seriously underestimated this cost in the earlier report, and that technical and environmental performance characteristics of *future* privately-financed plants will result in much higher O&M than in the past.²

We also wish to note that a one-tenth of a cent (i.e., one mill) reduction in the O&M cost for CCGTs would reduce the project net benefit by about US\$27 million. When compared with a Base Case project NPV of US\$266 million,³ the economic merit of NT2 would remain positive over a wide range of O&M assumptions.

B. Transmission Cost Assumptions

We are happy to clarify how transmission charges were applied for the study. The Bank and EGAT thoroughly discussed the cost basis for the required link between the Thai border and the 500 kV grid (at Roi Et), making certain that the capital cost assigned to NT2 for this required link neither exceeds nor understates the value of the works required to evacuate NT2 power to Thailand. This cost was estimated as US\$135 million (US\$82 million in present value terms), and that amount was added to the capital cost of NT2 for the least cost economic analysis. (The

¹ This value is net of the 0.2 US cents/kWh assessed for CCGT-associated transmission, as discussed separately in Section B.

² This trend was also noted in a recent article entitled “Service to the (GT) Fleet” in the August 2005 issue of *Power Engineering*.

³ The Bank’s Project Appraisal Document (PAD) reports the Base Case NPV at US\$266 million as well as results of several sensitivity analyses. The RELC report reviewed several scenarios, including one using the cost-risk framework on an incomplete data set which reports NPV at US\$188 million, but the decision document on project appraisal is the Bank’s PAD (see website link reference WL5) as explained in Section F of this letter. (Note: web link references are listed at the end of this document.)

cost of the line from the project site to the Thai border was already included in the NT2 project capital cost.) For purposes of the commercial analysis, EGAT's own estimate of the average commercial cost of import-associated transmission development in the Northeast (US\$ 0.00615/kWh) was added to the NT2 tariff to value each kWh purchased from the project.

All CCGT energy (in both the economic and commercial analyses) was assessed a transmission charge of US\$0.002/kWh⁴. This value is a generic estimate based on international experience with the all-in costs of building and operating high voltage transmission lines and substations; it provides for both the capital and operating cost of transmission works to the level of the first substation for generation-associated transmission and associated transmission reinforcement down to that level. The Bank did not consider it necessary to conduct a specific study for estimating this variable since a small variation in its value would not have a material impact on the overall conclusions of the analysis. In any event, for reasons explained immediately below, the Bank's assumption is most likely a low one.

The Northeast of Thailand is relatively under-provided with primary energy resources and depends considerably on energy flows from other regions to meet its electricity requirements. Once NT2 is commissioned, its production will be to a considerable extent absorbed in Northeastern Thailand. In a production/transmission structure without NT2, those loads, and in any event other load growth in Northeastern Thailand, would need to be served by relatively long transmission lines bringing thermal energy into the Northeast, as there is no natural gas transmission network that would allow the construction of CCGT capacity close to those load centers. The economic cost of transmitting NT2 firm energy from the Thai:Lao border to Roi Et is about 4.2 mills per kWh, based on the investment cost of US\$135 million plus associated O&M, or more than twice our assumption of US\$0.0020/kWh for associated CCGT transmission. However, we have used a conservative estimate of 2 mills per kWh for the average incremental CCGT transmission charge on the assumption that some future CCGT plants may be built closer to load centers.

C. Valuation of THB Power

In the system planning for hydro development in Lao PDR, it has long been accepted that the development of NT2 would reduce the energy output of the Theun Hinboun (THB) plant by 275 GWh per year.⁵ Indeed, that reduction was assumed in the economic appraisal of the THB plant. For the NT2 assessment, however, the Bank took the conservative view that this reduction of energy supply from THB is real, and, therefore, should be considered as a cost to the NT2 project.

⁴ By comparison, European Transmission System Operators (ETSO) charges are in the range of US\$0.0030/kWh to US\$0.0100/kWh with an average of around US\$0.005/MWh (US cents 0.5/kWh), which is much higher than what has been assumed in the RELC. Source: ETSO Tariffs Taskforce, Comparison on Transmission Pricing in Europe: Synthesis 2004, April 2005).

⁵ See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter to Messrs. Greacen *et al* found at website links referenced as WL2 and WL3.

In determining how to value this loss, the important question to ask is how the existing demand now served by THB will be met.⁶ The answer is that it will be met by increased thermal energy production from plants already operating on the Thai grid. These plants collectively will require more fuel and variable O&M in order to meet the shortfall. At the same time, THB will produce the same maximum power level at the time of Thailand's peak demand, so the energy reduction will not increase the need for generating plants. As a practical matter, it should be noted that the least-cost analysis does not "assign" a value to the reduction of THB energy; rather the system optimization model simply replaces this energy through increased production from the next lowest cost source, which happens to be existing CCGT capacity.

D. Renewable Energy, Demand Side Management (DSM)/Conservation, and Cogeneration Assumptions

As previously explained,⁷ for the renewable energy (RE) component, only firm capacity that is economically superior to NT2 needs to be taken into account for the purpose of the economic analysis. Table 39 of the Danish Energy Management (DEM) report⁸ identifies 300 MW of firm RE potential that is economic, of which 274 MW is considered in that report as practically feasible. In the 2003 Power Development Plan (PDP), EGAT had programmed 223 MW of such capacity up to 2006.⁹ This is retained in our analysis. The residual 51 MW (274 MW potential minus the 223 MW included) that is not retained in our analysis is less than 1 percent of the total incremental capacity Thailand is expected to commission between 2004 and 2011. EGAT's obligation is to provide 5 percent of incremental capacity from renewable sources over the next six years. This will result in approximately the range of renewables development discussed here. Hence there is no significant difference between the NT2 project analysis, the DEM Report and EGAT's development obligations in respect of this capacity.

As previously explained,¹⁰ the Bank carefully reviewed the DEM report on demand side management and conservation, and compared the data on economic potential presented in that report with past performance in order to assess what is likely to be achieved over the next several years. Successful development of a DSM program requires more than potential; it requires concrete programming, budgeting, financing, etc., which are not in place at this time. The Bank concluded that the amount of DSM included in the 2003 national demand forecast (920 MW by 2011) is a reasonable estimate of what is likely to be achieved.¹¹

We hasten to add that this does not mean that the Bank does not support and encourage such developments but simply that a higher level of DSM can not be considered as a simple option to be selected or de-selected at will. It is unlikely that a power utility would stake its power balance

⁶ It is important to note here that this is purely an issue of supply, and therefore it would be incorrect to value this energy as incremental electricity demand as you have suggested in your letter.

⁷ See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter to Messrs. Greacen *et al* found at website links referenced as WL2 and WL3.

⁸ Impact of Energy Conservation, DSM and Renewable Energy Generation on EGAT's Power Development Plan (PDP), Peter du Pont, Danish Energy Management, 24 March 2005.

⁹ This is also stated in the DEM report page 54, bottom of the page.

¹⁰ See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter and December 17, 2004 letter from Mr. Robert Mertz to Messrs. Greacen *et al* found at website links referenced as WL2, WL3 and WL4.

¹¹ Throughout this note the "2003 demand forecast" refers to the August 2002 forecast of the Thailand Load Forecast Subcommittee, and the "2004 demand forecast" refers to an update prepared in January 2004.

on hard-to-predict DSM decisions made by millions of consumers, and it is not practically feasible to fine-tune the commissioning date of a major generation project according to the uncertain flow of progress on DSM targets.

In addition to the Base Case assumptions described above, the project economic analysis has addressed this issue in two other ways. First, the study relies on the more conservative 2003 national demand forecast, which is 2,097 MW lower than the January 2004 forecast for the year 2010 (27,711 MW as compared with 29,808 MW in the more recent projections). As indicated in our letter of March 30, 2005, even if all of the prospective DSM/EE savings were to be realized in the planning period, it would delay the optimal NT2 commissioning date by less than a year. This, however, does not negate the project's long-term economic viability. Further, this issue is also addressed in our study through the risk analysis. The estimate recommended for DSM in the DEM report is far less than the 5,792 MW margin between the base case and low case demand forecasts for 2010 in the Bank's risk analysis.

With regard to cogeneration, as mentioned previously,¹² relative to Thailand's total potential, only a small amount is likely to be offered for sale to the power grid. That portion is reflected in our study through small power producer (SPP) plants fired by agricultural waste products. Most cogenerated power is designed to serve off-grid agro-industrial enterprises. These loads were not included the grid demand forecast, and thus should not be included in the grid supply program used to evaluate NT2.

E. Committed Plant and Retirement Assumptions

Each time that Thailand revises its national demand forecast, EGAT amends the supply forecast commensurate with its goal of maintaining a 15 percent reserve margin. (A fundamental premise of the Bank's analysis, supported by successive PDP documents, is that Thailand will reduce its reserve margin to this level by 2010.) This supply forecast includes retirements, repowerings, and new capacity (self-built, IPP, and SPP). Part way through the preparation of the NT2 economic analysis, Thailand published a new demand forecast which projected substantially more peak load than assumed in the 2003 demand forecast being used in the Bank's work. The Bank conservatively decided to remain with the 2003 forecast, despite the fact that a lower demand forecast is less supportive of the 2010 commissioning date for which NT2 had been contracted.¹³ That decision then required a careful plant-by-plant review with EGAT in order to determine which plants must be included as firm supply, and which should be candidates. The criterion for including a plant as firm capacity is that, at the time of the modeling work, contracts are irrevocably committed and financed with penalties for unilateral cancellation. Everything else, including repowerings (i.e., plants scheduled for retirement that can be re-conditioned for extended service) are treated as candidates. The proposed 700 MW CCGT plants you cite as "omissions" in your letter (Songkla - 2007, North Bangkok - 2009, South Bangkok - 2009, and Bang Pakong - 2010) were *not* committed plants under this definition, and therefore were evaluated as generic CCGT candidates. These plants were not excluded from the analysis, but

¹² See December 17, 2004 letter from Mr. Robert Mertz to Messrs. Greacen *et al* found at website link referenced as WL4.

¹³ As a practical matter, and given that our existing analysis was more conservative, it was not reasonable to ask EGAT system planners to re-specify all the input data for a completely new cost-risk analysis.

treated as candidates in the planning model.

That model determines which new supply candidates are economic, and schedules capacity based on least-cost criteria. The results for the base case demand forecast recommend four new CCGT plants for 2008 - 2010 (mirroring those which you cite as “committed plants”), along with the development of NT2 and subsequent new capacity (including repowering) that is economically justified, while maintaining the target reserve margin.¹⁴

F. Risk Analysis

We regret any confusion that may have arisen in reviewing the RELC cost-risk analysis. To restate for the sake of clarity, the study does evaluate high, base, and low case scenarios for NT2 construction costs, but only base and low case scenarios for the two other sensitivity variables, the demand forecast and natural gas prices. Low construction costs were applied only for cases for which an offsetting high construction cost was also evaluated. This was not the case for the demand forecast and gas price scenarios, for which no high cases were evaluated. In order to apply the complete cost-risk framework, base case values were substituted for the missing high demand forecast and gas price scenarios. This approach in effect biased results against NT2, since these two variables were evaluated as 75 percent probability of base case and 25 percent probability of low case results. This approach explains why the results presented in RELC are lower than those presented in the formal Project Appraisal Document (PAD).¹⁵ The project has substantial risk margins built in at two levels (procurement and construction), with fixed price commitments and penalties, but we still assigned a 25 percent probability to a 30 percent cost-overrun.¹⁶

In this regard, it must be noted that the PAD, developed from the RELC supporting study, is the definitive document presented for the decision of the World Bank’s Board on NT2. That document concludes that the Base Case economic benefit from NT2 is on the order of US\$266 million. The Bank's statement of the Economic Cost-Risk analysis is presented in Annex 11, Section A.4, of the PAD; the scenarios calculated for this purpose are displayed in Table 5 on page A129 and explained in the text. Table 5 has scenarios with elements favorable and unfavorable to NT2 as explained. All cases for which there is at least one element of the key assumption set that could have a significant downside risk for NT2 are reported and the implications of the range of results are explained in paragraph 43 of Annex 11.

The Bank appreciates and shares your concern about the impact of electric power projects on the electricity prices that ratepayers will face. We acknowledge that if for whatever reason Thailand fails to bring its reserve margin to the target level over the time period programmed, the system would by definition be carrying unnecessary, excess capacity. This is a broad systemic risk that depends on overall demand and supply conditions and not on the NT2 project alone. NT2 will

¹⁴ See RELC, Table 18, p. 47. Of course, many of these candidates are not economic under a low demand scenario, and are therefore not selected by the model as capacity additions; see RELC Table 20, p. 50.

¹⁵ World Bank Report No. 31764-LA, March 31, 2005. See website reference link WL5.

¹⁶ Compared to average cost under-estimation of 27 percent reported in 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.

contribute to meeting less than five percent of Thailand's incremental energy demand growth between 2004 and 2015 inclusive based on the 2003 demand forecast.

G. Bank Lending Policies

The Bank's financial support instruments do not subsidize power projects. The Bank's guarantees are developmental instruments designed to mitigate political risks not included in the commercial rate of return expected of similar projects developed in areas where covered risks are much lower. This is not a subsidy – it levels the playing field allowing certain countries to host projects that are expected to earn normal commercial rates of return. In the case of NT2, guarantees from the Bank and MIGA enabled the project to mobilize about US\$1 billion in private sector funding which would have been otherwise unobtainable. The NT2 project is therefore not being subsidized by the World Bank. The same instruments could be made available to any private power project that is economically justified.

Conclusion

Finally, in light of the foregoing considerations, we are of the view that the analyses underlying the decision to support the NT2 project are robust and that no useful purpose would be served by redoing them. In such analyses, there are always areas in which choices of assumptions and approach can be made, depending on the judgment of the analysts, about what is most relevant and reasonable for the situation at hand. Over the extensive period of time used to complete this analysis, the Bank's analysts have considered, in great depth, all of the issues you have raised. With the benefit of hindsight, of course, one may always point to this or that assumption or approach that could have been handled differently. For example, as stated in the PAD, page A128, paragraph 38, the values we adopted for natural gas "may well understate eventual long-term natural gas economic values." In light of current developments in international and domestic hydrocarbon markets, a higher gas price forecast for the analysis might have been more appropriate. However, the fact that the NT2 project is a fixed price contract for up to twenty-five years, partly based on hydrocarbon values as perceived when the contracts were negotiated, means that Thai consumers will have available about 1000 MW of stable, predictable and reasonably-priced energy supply from NT2. This is in the interest of all concerned parties.

Website Link References

WL1/ <http://siteresources.worldbank.org/INTLAOPRD/Resources/RELC2005v3.pdf>

WL2/ <http://siteresources.worldbank.org/INTLAOPRD/Resources/ResponseLetterApril82005.pdf>

WL3/ <http://siteresources.worldbank.org/INTLAOPRD/Resources/Greacen.pdf>

WL4/ http://siteresources.worldbank.org/INTLAOPRD/Resources/293582-1092106399982/492430-1092106479653/palang_thai_three_economists_response_from_robert_dec17-2004.pdf

WL5/ http://www-wds.worldbank.org/servlet/WDSContentServer/WDSP/IB/2005/04/08/000012009_20050408085158/Rendered/PDF/317640corr.pdf

Attachment 1: Comparative O&M Costs

World Bank Data

Source	FOM in UScents/kWh	VOM in UScents/kWh	Total O&M in UScents/kWh	Notes
USA 1	0.3567	0.2000	0.5567	1/
USA 2	0.1475	0.2070	0.3545	2/
India 1 ("Claimed")	0.0824	0.3294	0.4118	3/
India 2 ("Allowed")	0.0659	0.2634	0.3293	3/
Japan	0.1000	0.4000	0.5000	4/
USA (Cal 1)	0.2568	0.2500	0.5068	5/
USA (Cal 2)	0.2581	0.2280	0.4861	6/
China	0.1665	0.2561	0.4226	7/
Yemen 1 (low of 5, based on VOM)	0.0870	0.5430	0.6300	8/
Yemen 1 (high of 5, based on VOM)	0.0832	0.6060	0.6892	8/
Yemen 2	0.2072	0.3890	0.5962	9/
Southeast Europe (low of range)	0.1952	0.1560	0.3512	10/
Southeast Europe (high of range)	0.4110	0.2640	0.6750	10/
CCPP	0.1427	0.1800	0.3227	11/
CCPP	0.2140	0.2600	0.4740	11/
OECD (low of range)			0.0702	12/
OECD (high of range)			0.6758	12/
Palang Thai Data				
Thailand (RELC-2005 Table 15)	0.2568	0.5000	0.7568	13/
Thailand (RELC-2004 Table 13)	0.2397	0.0564	0.2961	
Thailand (EGAT)	0.2277	0.0536	0.2813	
USA (Cal) (CPUC MPR)	0.1514	0.2550	0.4064	
USA (Cal) (CPUC merchant CCGT)	0.1936	0.1360	0.3296	
USA (Cal) (CPUC utility-owned CCGT)	0.1936	0.1360	0.3296	
USA (Wash) (Puget Sound Energy)	0.1570	0.2000	0.3570	
Ireland (Comm. for Electricity Regulation)	0.1463	0.1260	0.2723	
Australia (NSW Regulatory Tribunal)	0.0371	0.3140	0.3511	

1/ 500 MW class, US plants. "O&M" includes items like plant staff, materials, insurance, auxiliary power, and ISO membership fees. Source: La Capra Associates, Boston, Massachusetts.

2/ Adv Gas/Oil Comb Cycle (CC). Assumes data is \$2002/kW-year (although expressed only as \$2002/kW"). No adjustment made for inflation from 2002 dollars. Source: EIA, Table 38.

3/ Data is for 2003-2004, from the Central Electricity Regulatory Commission - New Delhi, for "claimed" rate. Applying exchange rate of \$1=R42. Assumes Total O&M = 80% variable + 20% fixed. Data reported as "Rupees in lakh" (at 4363 for "claimed" by the power producer and 3489 for "allowed" by the regulator). Conversion made on the basis of 1 million Rupees=10 lakh. "As calculated" data uses 80% load factor for comparability. Originally-reported data was based on a 69% load factor, resulting in Total O&M of 0.4774 US cents/kWh for "claimed" (with imputed FOM of 0.0955 US cents/kWh and VOM of 0.3819 US cents/kWh) and 0.3818 US cents/kWh for "allowed" (with imputed FOM of 0.0764 US cents/kWh and VOM of 0.3054 US cents/kWh).

4/ Toyo Engineering / Chubu Electric. Assumes 25-year plant life; 80% capacity factor; 10% discount rate; ad 2004 price for 300 MW oil/gas fired combined cycle. O&M numbers are per kWh, which are based on levelized generating cost calculations over an expected 25 year life and are based on their experience in Japan with some 25-30 CCGT units. The cited numbers are from a draft study that is not yet finalized.

5/ Underlying data is from several new CCGT plants in California. Values reflected are values recommended by the regulatory bodies: California Wind Energy Association / California Biomass Energy Alliance / California Cogeneration Council). Note: Among the plants considered, the highest values for FOM and VOM both occurred with one plant and the values were \$36.0 \$/kW-yr and \$3.08 \$/MWh, respectively. Reference document available at:

<http://calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf>

6/ The table presents data from 6 plants and the resulting averages for FOM and VOM. The numbers presented above are those averages. Data is from Table 2 of reference document available at:

<http://calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf>

7/ Data is from feasibility report for project in Guangdong province, China. Exchange rate is \$1=RMB 8.26 Yuan (before) and about RMB 8.2 Yuan now. Capacity is 2x390 MW. Assumes data is Yuan per kW-year (although reported only as "Yuan/kW").

8/ Data is from a study conducted by PPA Associates (2002) and is drawn from 5 single cycle GT plants. Data is based on a GE turbine with ISO capacity rating of 122.5 MW and takes into account aging, altitude and ambient temperature.

9/ Data is from a draft World Bank report of September 20002. CCGT candidate assumes capacity of 362 MW plant at sea level. Variable O&M number cited is non-fuel.

10/ Data is from a Generation Investment Study in Southeast Europe. Variable O&M is taken from sources where some adjustments are made for local labor costs. VOM does not include fuel cost. Data is for a range of capacities from 150 MW to 500 MW. Assumes exchange rate of \$1.2=1Euro. December 2004 final report.

11/ Colenco Power Engineering Ltd. Combined Cycle Power Plant 400 MW. O&M costs do not include any provisions for fuel, insurance coverage or for taxes. Estimated annual O&M costs based on 7000 OH/a. Used 80% plant load factor.

12/ Data is from OECD/ AEN-NEA / IEA study: *Projected Costs of Generating Electricity* (2005 Update), Table 3.5 (Projected 2010 costs for gas-fired power plants). Data is reported as specific annual O&M costs (per kWe) by selected countries on a levelized generation basis. The "lower end of range" data presented under "as calculated" is based on the reported data for Greece ("GRC-G2" data point) and the "higher end of range" data is for the Slovak Republic (data point "SVK-G").

13/ Although the RELC (March 2005, Table 15) reports VOM as .007 \$/kWh (or 7 \$/MWh), this figure includes transmission costs of .002 \$/kWh (or 2 \$/MWh). To be on a basis comparable to the other data presented in the table immediately above (which does not include transmission costs), the correct VOM figure to use is .005 \$/kWh (or 5 \$/MWh).