Nam Theun 2 Project Economics
Interim Summary Report

August 21, 2004

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Introduction:

The Nam Theun 2 (NT2) power project's primary source of value added is the Thai power market, to which it will export about 95% of its expected annual energy production (5354 GWh), the remaining 5% (up to 300 GWh) being for the Lao power market. The first economic question is whether NT2 commissioned in 2009 would be a least-cost means of producing electricity for both countries, including the project's associated environmental and social costs. Prospective electricity demand and supply conditions in the Thai power market are the key elements needed to answer this question. The next economic question is whether the value of electricity to end-users is high enough to recover the project's comprehensive costs at an adequate economic rate of return (ERR). Thirdly, because the project has costs and benefits to public and private parties in several countries, there is a question about whether the project's net benefits are distributed reasonably between the parties. These three questions – (1) whether the project is least-cost, (2) whether the ERR is satisfactory and (3) whether the distribution of net benefits is reasonable - are addressed in this paper.

Because the project's costs and benefits will occur over a 30 year time period, the future values of many factors entering these analyses are uncertain. Therefore, considerable risk analysis was undertaken to determine the robustness of "base case" findings.

This economic analysis is work in progress. From early 2003 to now, there have been real cost increases for NT2 and the thermal power alternatives, as well as an increase of the Thai electricity demand forecast from the growth rates forecasted in August 2002 and used in the base case analysis. Also, aspects of the environmental and social cost-benefit accounting and an up-date of the options for the Lao power market are nearing completion, hence the current results do not include those forthcoming findings. The results presented below use the most recent information available to us - except as noted, and will be up-dated once the remaining studies permit.

[A] Is NT2 Part of a Least-Cost Power System Expansion Program?

We address this question from two perspectives: economic and commercial. The economic perspective asks whether the project is an efficient use of incremental real resources compared with alternatives ways of meeting the same power needs. The commercial perspective asks whether the project is likely to be commercially competitive with these alternatives. The answers are not necessarily the same for both questions, because some of the values differ between the two perspectives. The main valuation differences are that economic valuation excludes sunk costs and taxes[1], uses real values

[1] Sunk costs are excluded because they are expended and therefore allow no future choice; taxes are transfers of value-added, not resource costs, therefore excluded from economic valuation which deals only with real resource costs.

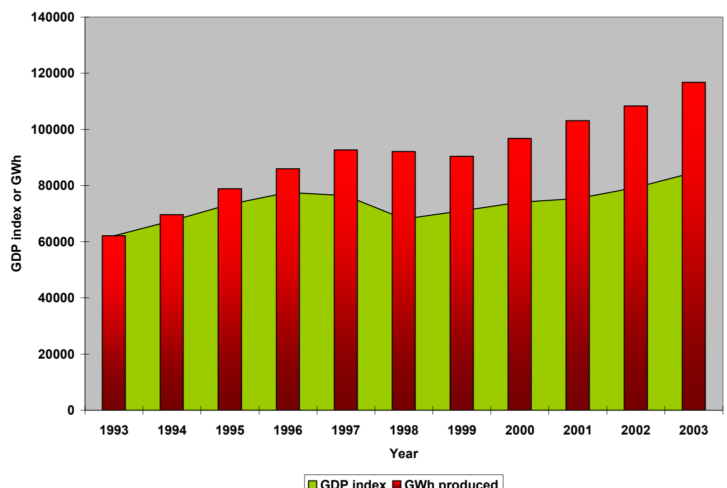
of costs[2], and evaluates capital at a 10% social discount rate, while commercial valuation includes sunk costs and taxes, and uses current values of costs, commercial rates for debt and investor hurdle rates for equity. Thus, the same project that is least-cost economically can seem commercially marginal once laden with the sunk costs and taxes that power purchase contracts need to recover, but are not relevant to economic analysis.

Because power plants have differing front-end investment costs and future operating costs, the demand forecast can influence whether one project is a more economic "fit" for the market than another. It also influences the appropriate timing of the project's commercial operation. Hence the starting point of the least-cost analysis is the demand forecast for the Thai and Lao power systems.

Thai Power Market: Between 1993 and 2003, the growth rate of electricity demand has exceeded that of GDP. Average annual GDP growth was 3.1% and that of electricity demand 6.5% (Graph 1). In 2003 GDP grew by 6.7%, well above the 5% range previously forecasted.

Graph 1. Electricity consumption and GDP Growth (Thailand, 1993-2002)

(The base of the GDP index is scaled to the level of 1993 electricity consumption for ease of comparison.)



In April 2003 the Thai system load peaked at 17,826 MW, with installed capacity of 25,378 MW.[3] The reserve margin was 35%, after adjusting for hydro availability, indicating excess capacity relative to the system reserve criterion of 15%. By April 2004, peak load had grown by 1502 MW, or 8.4%, consuming about one-third of the excess capacity in one year. Peak load exceeded the 2002 forecast by about 300 MW.

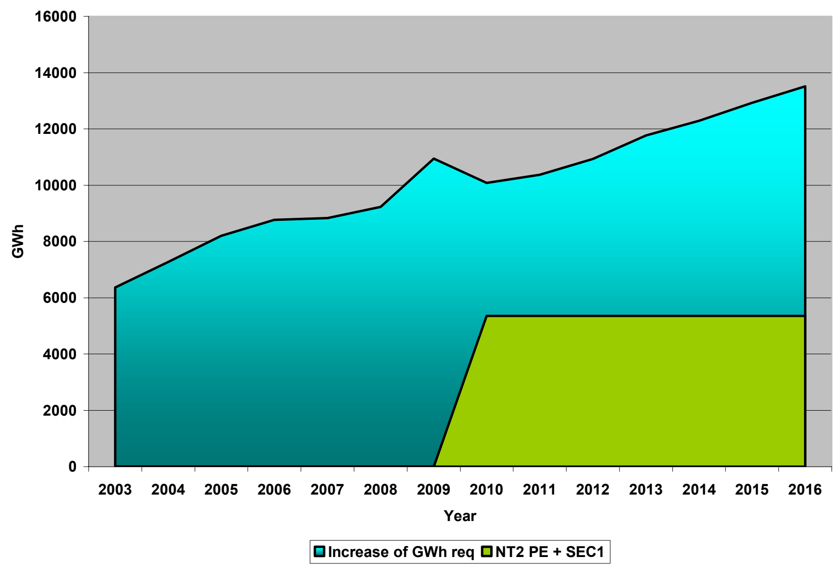
Thailand currently has considerable surplus generating capacity, because of the economic downturn in the late 1990s and the large amount of capacity that was under development and could not be stopped on reasonable terms. With economic recovery, electricity demand growth has resumed and surplus is eroding. The Thai power market is very large, hence low rates of change on a large base causes both large reductions of surplus capacity

[2] Nominal costs are converted to real costs using the U.N. MUV index of February 2004.
[3] Appendix 2, Table 2.1.

in the medium term and requirements for much new capacity over the longer term, even after including realistic estimates of demand management and energy efficiency savings. While Thailand's 995MW from NT2[4] sounds large, this analysis indicates that by 2009/10 it is likely the capacity will be needed to meet the system reliability criterion (15% reserve margin) and will be absorbed in less than one year of demand growth.

Thailand has a sophisticated, institutionalized electricity demand forecasting process. The August 2002 forecast projects energy consumption growth of about 6.2% per year from 2003 to 2016. Peak load will grow at about the same rate, implying a stable system load factor of about 0.73. At this growth rate, the annual increase of energy requirements starts at 6371 GWh in 2003 and becomes 10,940GWh in 2009. NT2 will supply Thailand with about 5354 GWh or roughly half the consumption growth of 2009 (Graph 2).

Graph 2. Thailand: Increase of Annual Generation versus NT2 Supply from 2009



The demand forecast includes a projection of 928 MW capacity savings through demand management. The Bank believes there is scope for as much as 1000 MW of additional savings; however, achieving it depends on aggressive programming and high consumer up-take. Even if successful, it would delay the next large power plant by very little. Thailand's 2004 demand forecast indicates load growth exceeding 7% per year. The Bank has chosen to remain with the lower 2002 demand forecast[5] (about 6.1%/year demand growth for the base case), but the implications of higher and lower demand growth are examined. At the 7% rate of demand growth in the 2004 load forecast, Thailand's capacity surplus would disappear before 2009.

[4] NT2 total installed capacity will be 1070 MW.

[5] Despite the existence of this more recent, and higher, official projection of electricity demand growth we base this analysis on the August 2002 forecast for several reasons. (1) Lower demand growth is a more severe test of the project's merits than higher growth, (2) our forecast range more than covers the higher growth rates of the 2004 forecast, and (3) the results of this analysis indicate that the time and cost of a complete up-dating based on a higher demand forecast are not worthwhile as NT2 cannot be commissioned earlier than 2009 and it is quickly absorbed once available.

Laotian Power Market: Lao PDR will be committed to buy 200GWh of NT2 energy (starting with lesser amounts over 2009 to 2012), but may buy up to 300GWh per year. Lao's electricity supply system is small and consists of four grids, none of which are interconnected. NT2 would serve Central Region 2 (CR-2), one of the two larger central grids including Savannakhet and Thakek.

The load in CR-2 is about 40 MW, served with imports from Thailand and some energy from Nam Ngum 1. CR-2 demand is expected to grow rapidly, given the small size of present consumption, the large scope for electrification, the big market for irrigation pumping (to replace unreliable and expensive Diesel pumps), plus air-conditioning, some industry, and government administration. Electrification is being financed mainly by the Asian Development Bank (ADB), Japan and the International Development Association (IDA). In addition, the Oxiana gold mine began operating in 2003 and will employ up to 1600 people. It needs 20-30 MW of power, which it will import power from Thailand for the time being. It can be served by NT2 with a sub-transmission line. Two towns (Thakek and Savannakhet), now get their power from Thailand, but could take it from NT2 when available. They can absorb about 50 MW. Between these two towns and the gold mine, the Lao allocation of NT2 can be more than absorbed.

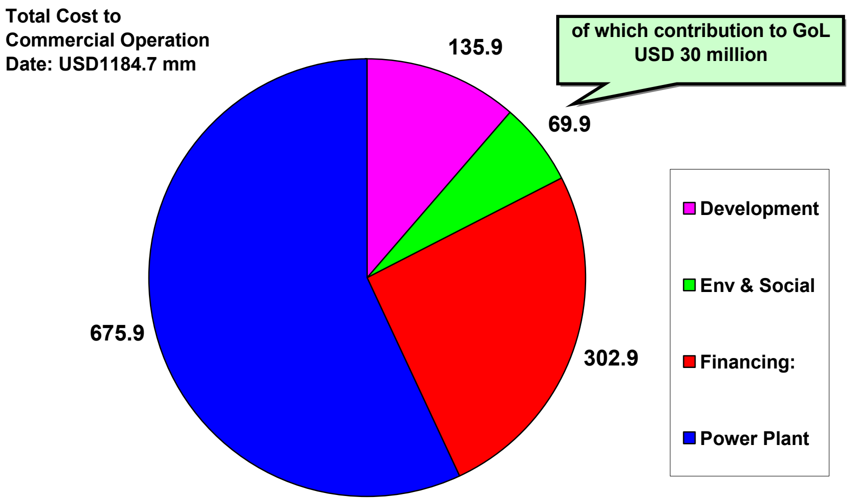
Investment Timing: With this demand outlook, the next questions concern the appropriate timing of new power plants and the comparative costs of NT2 and gas-based thermal power plants, given Thailand's access to large volumes of natural gas.

The appropriate timing of NT2 was evaluated using EGAT's version of PROSCREEN, an internationally well-established power system programming model that analyses a large number of supply and demand factors to produce an economically optimized generation expansion program including timing and choice of technology. Among the factors included in this analysis are about 5900 MW of already contracted new capacity over 2003 to 2009 and 2790 MW of planned retirements, about 900 MW of which are included as candidates for refurbishment if the modeling determines refurbishment to be cost-effective. On this basis the model shows appropriate timing of NT2 for 2009, which is the earliest year in which it could be commissioned.[6]

Comparative Cost Estimates: This result, and the overall cost-effectiveness of NT2 depends on the demand forecast (discussed above) and relative costs of NT2 and its next best alternatives. The expected base financial cost of the NT2 project is USD 1185 million (Graph 3). This is not the final cost, as some contracting remains to be completed and some up-front environmental and social items are under preparation.

[6] This result was obtained with a project cost about USD 116 million less than the current project cost. When the analysis is up-dated, based on the size of NT2's economic advantage and increases in the costs of thermal options, we do not expect the result to be over-turned.

Graph 3. NT2 Financial Investment Cost Structure



Note: This graph shows higher financing costs and lower development costs than in Table 1, Section 1, because in this graph "bonding charges" and "finance contingency" are shifted from "Development" to "Financing" and the "Environmental/Social" category is separated from "Developmental Pre-Op".

The conversion from the project's financial cost to its economic cost of USD 989 million for the region is shown in Table 1. The environmental and social programs to be implemented during the construction (Table 2) are expected to cost about USD 40 million. Apart from this, the NTPC transfer to GoL of USD 30 million includes a refund of about USD 7.5 million for costs GoL has already incurred plus another USD 22.5 million as compensation for reduction of future economic benefits from the reservoir area.

Table 1. NT2 Project Cost: Commercial and Economic

1. Project Cost Provided in Financial Model	USDmm
1.1 Developmental Pre-Op (incl. GoL contribution)	251.1
1.2 Head contract costs	675.9
1.3 Financing costs	257.7
Total Financial Cost	**1,184.6**
2. Conversion to Economic Cost	
2.1 delete financing costs	-257.7
2.2 delete sunk costs & finance contingency from 1.1:	-84.9
2.3 delete portion of GoL contribution	-7.5
Total nominal cost of economic items:	**834.6**
Adjustment from nominal to real economic items values	19.6
Transmission line in Thailand	135.0
Total real cost of economic items:	**989.1**

Notes:
(i) Financing costs (interest during construction and fees) are replaced in the economic analysis by the 10% social discount rate when doing NPV calculations, or they are internalized in the ERR calculation because the expenditures are spread over 5 years. (ii) The finance contingency is provided for the risk of interest rate escalation in the commercial costing. . (iii) Sunk costs are funds expended to end 2003. (iv) The adjustment from nominal to real values uses the U.N. MUV index which projects a slow rate of international deflation from 2004 to 2009.

Table 2. Pre-Op E&S Programs

Surveys, relocation
External monitoring
UXO survey, clearing, resettlement
Resettlement Mgmt Unit, DRWG, RC
Training resettlers, income gen.activity
Village sites, houses, farm equipment
Infrastructure design, equipment
Regional Health program
Resettler health program
Community forestry program
Livestock improvement program
Agricultural development program
Reservoir fishery development pgm
Provide other livelihood equipment
Community development
Income support
Entitlement to PAPs along XBF
Compensation project lands
Fish studies downstream of Nakai
Revise NT morphology study
Water quality improvement; remove biomass
Wildlife management/protection
White winged duck program
Elephant program
Public education re environmental issues
Animal protection during impoundment
Environmental Management Unit
Independent environmental monitoring
Water quality monitoring/assessment pgm
Watershed Management & Protection Auth.

During the project's 25 year operating period under the power purchase agreement (PPA), the project will incur about USD 427 million (excluding inflation) in operation and maintenance costs, of which USD 59 million will be for the on-going expenses of NT2 watershed management, resettlement and environmental and social (E&S) monitoring and mitigation. The approximate USD 121 million of economic E&S costs reported here (USD 40 million during construction, USD 22 million GoL compensation and USD 59 million during operations) are those recognized by the sponsors and included in the financial model. They could be more or less than the total projected value of E&S impacts, as some are still being assessed in the studies nearing completion. The project's economic costs will be further adjusted once this information becomes available. The other main recurrent costs include NTPC administration, insurance, power plant operations, routine maintenance and major maintenance.

The levelized economic supply cost of electricity from NT2 in real USD of 2004 is projected at about $ 0.027/kWh based on all of the above mentioned economic costs.[7] This cost must not be interpreted as commensurate with a tariff for NT2, because the tariff is based on commercial costs, which differ substantially from economic costs, as discussed below. The economic accounting of NT2's costs and benefits is limited to the duration of the PPA, even though the project will undoubtedly provide economic benefits for decades beyond. At this time, it is difficult to predict a valuation basis so far into the future. As well, the present value of those costs and benefits are very low because they are so distant, hence an effort to estimate them would not substantially affect the results obtained to 2034. Nonetheless, they exist and there can be little doubt they will be meaningful to future generations.

Economic Least-Cost Analysis: The PROSCREEN modeling indicated that absent NT2, EGAT's next best alternative is to build and operate more combined cycle gas turbines (CCGT).[8] Lao's next best option would be to import more energy from EGAT, the price of which is based on the costs EGAT faces for generating and transmitting additional guaranteed thermal capacity and energy.[9]

We have reviewed the costs of CCGT plants recently completed in the region and similar to EGAT's basic configuration, as well as the projected long-term costs of natural gas based on current contracting practices in Thailand. On this basis, we estimate the long-term delivered economic cost of CCGT energy should be approximately USD 0.038/kWh. This estimate includes capital cost of USD 510/kW before financing, 10% real social discount rate on all capital employed, a 25 year plant life, fixed operating costs of USD 18.00/kW/year, variable operating costs of USD 0.007/kWh, a long-term fuel

[7] A "levelized supply price" is a long-term representation of average cost per unit of production needed to recover the project's investment and operating cost for all the GWh produced over the accounting period. The resulting 2.7 cents/kWh economic cost is derived from dividing the present value of energy production into the present value of investment and operating costs. Present values are calculated using a 10% real discount rate.

[8] This modeling remains to be up-dated with these latest investment and operating cost estimates of NT2 and thermal power reported here.

[9] This is indicated in previous studies of the Lao power system and will be reconfirmed in the Lao Power System Development Plan now nearing completion.

cost of USD 2.54/mmbtu, a heat rate at 7050 btu/kWh, and an allowance for generation-associated transmission.[10] As for NT2 economic costs, all of these costs exclude taxes and general inflation.[11]

The valuation of natural gas in the Thai power market depends on numerous factors, the key ones being supply costs from the Gulf of Thailand, import costs from Myanmar, the price of fuel oil f.o.b. Singapore, the Thai tax and royalty regime and the cost of transportation from well-head to end-users. About 80% of the natural gas market in Thailand is for power generation. The natural gas industry considers the resource base adequate for many years to come. Natural gas contracts are structured so that notwithstanding continually fluctuating oil prices, gas producers are not exposed to critically low returns at the well-head when oil prices are low and consumers not exposed to extreme price spikes when oil prices are high. The Bank's estimates of economic value for natural gas are based on the Bank's world oil price projections and its understanding of generic resource costs, tax regimes and contract structures applicable in Thailand.

CCGT plants require much less planning and implementation lead time than does NT2. As CCGT capital costs and natural gas values fluctuate with market conditions, closer to the time EGAT would require this capacity absent NT2, both capacity and fuel costs could be higher or lower than the above estimate. (However, the PPA tariff for NT2 is fixed in USD and THB for at least the first 12 operating years, and then only subject to modification for the remainder of the PPA if Thailand were to create and operate a power pool conforming with definitions and conditions in the PPA.)

Hence with the economic price of NT2 energy at US 2.7 cents per kWh and that of CCGT energy at US 3.8 cents per kWh, there is a real, undiscounted economic cost saving of about USD 60 million per year every year that the two countries are supplied with about 5554 GWh of NT2 energy. With the economic cost of NT2 energy being roughly 70% that of CCGT energy, there is considerable scope for changed values of key assumptions before NT2 would become uneconomic. For example, all else being equal, the cost of natural gas would need to be about 38% of its projected value for CCGT to cost the same as NT2. Again, we remind readers that these are economic values, not commercial tariff estimates.

Comprehensive Risk Analysis: We conducted a comprehensive "cost-risk" analysis[12] to test whether a decision now to implement NT2 for commercial operation in 2009 (the “NT2 Option”), versus not implementing it, is robust to a range of alternative outcomes for the key factors that could change in the future and would affect the net present value

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[10] In this context we note that geographically NT2 is well positioned to reach a North-Eastern area of Thailand that would be costly to reach with CCGT facilities.

[11] We also use low and high gas prices of USD 2.30 and USD 2.80 per mmbtu respectively for risk analysis.

[12] The following description of this analysis draws on 2003 cost assumptions now out-dated, having lower costs for both NT2 and CCGT than outlined above; however, the analysis has not yet been re-run with new values. Nonetheless, we present it in some detail to explain the methodology that will be carried forward in the forthcoming up-date. We also have reason to believe the direction of the results will be sustained with the up-dated assumption set.

(NPV) of the NT2 option. The hypothesis is that once all the necessary contracts and approvals are in place the project proceeds despite uncertainty about the future economic environment that can affect it.

The cost-risk analysis recognizes that the key risk factors described below are essentially uncorrelated and any combination of them could occur, but no-one knows which will actually occur. Thus, the NT2 option would be exercised knowing this uncertainty and the objective is to determine whether the option has positive NPV (at 10% economic discount rate) relative to the alternative decision of not building the project, taking all the tested risk values and their probabilities of occurrence (PO) into account.

In this project, the three factors that could have the biggest impact on the NPV of the NT2 option are NT2 project costs, the demand forecast and the value of natural gas. The PO of any one combination of these factors depends on the number of possible combinations of the factors and the individual POs assigned to the high, base and low values for each factor. In this analysis, the "With NT2" scenarios include three demand forecasts, three NT2 cost estimates and three natural gas price projections, resulting in 27 possible combinations of different conditions. The "Without NT2 scenarios include three demand forecasts and three natural gas price projections, resulting in 9 possible combinations of different conditions. The resulting structure of the cost-risk matrix is shown in Graph 4.

Graph 4. Structure of the Cost Risk Matrix

	A	B	C	D	E	F	G	H
1	With NT2 (the NT2 Option)					Without NT2		
2	Project	Demand	Nat Gas	PO		Demand	Nat Gas	PO
3	Cost	Growth	Value	weight		Growth	Value	weight
4	0.25	0.25	0.25	0.0156		0.25	0.25	0.0625
5	0.25	0.25	0.50	0.0313		0.25	0.50	0.1250
6	0.25	0.25	0.25	0.0156		0.25	0.25	0.0625
7	0.25	0.50	0.25	0.0313		0.50	0.25	0.1250
8	0.25	0.50	0.50	0.0625		0.50	0.50	0.2500
9	0.25	0.50	0.25	0.0313		0.50	0.25	0.1250
10	0.25	0.25	0.25	0.0156		0.25	0.25	0.0625
11	0.25	0.25	0.50	0.0313		0.25	0.50	0.1250
12	0.25	0.25	0.25	0.0156		0.25	0.25	0.0625
13	0.50	0.25	0.25	0.0313			TOTAL>	1.0000
14	0.50	0.25	0.50	0.0625				
15	0.50	0.25	0.25	0.0313				
16	0.50	0.50	0.25	0.0625				
17	0.50	0.50	0.50	0.1250				
18	0.50	0.50	0.25	0.0625				
19	0.50	0.25	0.25	0.0313				
20	0.50	0.25	0.50	0.0625				
21	0.50	0.25	0.25	0.0313				
22	0.25	0.25	0.25	0.0156				
23	0.25	0.25	0.50	0.0313				
24	0.25	0.25	0.25	0.0156				
25	0.25	0.50	0.25	0.0313				
26	0.25	0.50	0.50	0.0625				
27	0.25	0.50	0.25	0.0313				
28	0.25	0.25	0.25	0.0156				
29	0.25	0.25	0.50	0.0313				
30	0.25	0.25	0.25	0.0156				
31			TOTAL	1.0000				
32	HIGH	MEDIUM	LOW					

(Note: The PO of each value assumption is shown inside its respective cell. "MEDIUM" = base case.)

The POs and their variance were selected for this project based on two considerations: (i) experience of how the values of key factors have varied from expected values in other relevant situations, and (ii) the POs should give more weight to the base case than to the high or low cases. We have selected a 50% PO for base case values and a 25% PO each for the high and low values. The variance of each tested factor is related to those POs.

World Bank internal research on the experience of **hydro project investment costs** suggests a range of plus or minus 30% around the base case estimate is valid at 25% PO.[13]

Demand forecasting experience in Thailand and elsewhere suggests that at 25% PO, demand can be as much as 25 percentage points above or below estimate by the tenth year into the forecast. While the forecasting techniques may be very good, the demand for electricity is a derived demand, the underlying determinants of which are hard to predict (e.g. GDP growth, personal disposable income, household formation, commercial and industrial investment activity, and technical change).

Variance in the **value of natural gas** under Thai conditions depends mainly on uncertainties about future sourcing having different cost profiles and on the international values of alternative fuels. The base case and lower probability cost estimates were developed from a combination of World Bank oil price forecasts and proprietary information that natural gas producers and users in Thailand provided to the Bank, with understandings on confidentiality.

Having determined the factors, value ranges and POs entering the analysis, the remainder of the calculation process consists of listing all the cases with and without the NT2 option in a systematic matrix as shown in Graph 4. Then the PV of each case is calculated using EGAT's PROSCREEN and weighted by the PO specific to that case. The weighted PVs for all cases within the NT2 option are summed, the result being the probability-weighted PV of the NT2 option, all the variations considered. The same process is repeated for all cases of the least-cost non-NT2 option and its probability-weighted PV determined. The NPV of the NT2 option is the difference between the probability-weighted PVs of the two options. As this is a PV cost comparison, the preferred option is the one with the lower probability-weighted PV.

The result is that the NT2 Option has an NPV preference of USD 269 million over the 30 year project life. The range of scenario results contributing to this value is shown in Graph 5. Within each cost estimate for the NT2 project, the low end of the savings range reflects low demand and low natural gas prices, and the high end the opposite.

[13] This means there is a less than 25% probability that actual costs could deviate from expected costs by more than 30% above ore below the expected cost.

Graph 5. PV Savings for the NT2 Option per NT2 Cost Estimate (USD million)

NT2 Cost	Range of PV Cost Saving*
high	- 63 to + 193
medium	+ 111 to + 367
low	+ 286 to + 542
*according to gas value and demand	

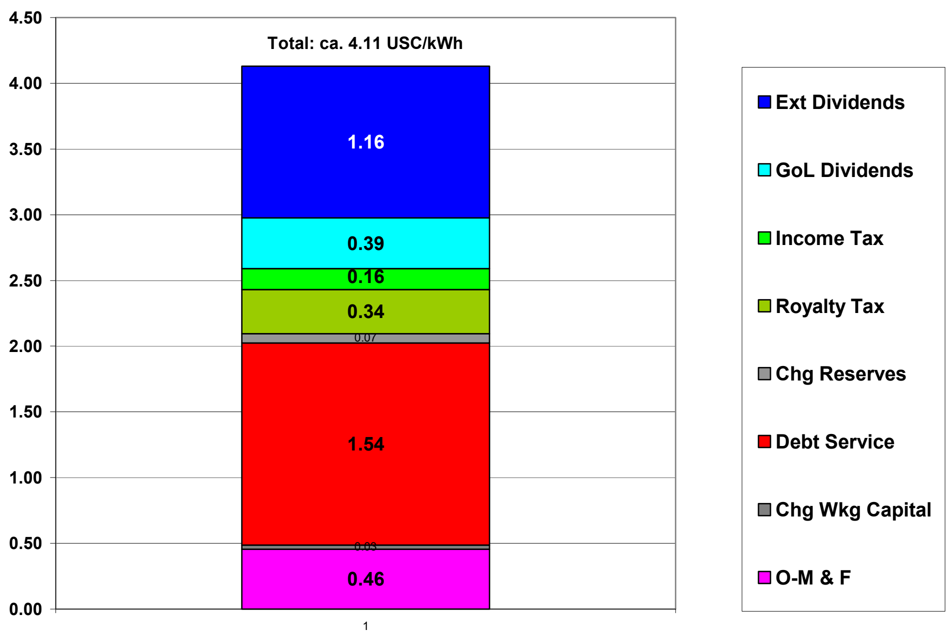
These estimated savings are large and robust, because it requires a combination of all the worst case conditions that we tested against NT2 (high project cost, low demand and low natural gas value) to derive a negative NPV for a scenario including NT2; it has a PO of just 1.56%. Apart from the case with a negative NPV, only three other cases – out of twenty-seven - have NPV of less than USD 100 million favoring the NT2 Option. All three of them combine the high project cost assumption with either a low gas price or low demand forecast and each of them have a PO of no more than 3.1%. The project survives low demand risk by displacing thermal generation; also, there is flexibility to delay other new projects beyond NT2's commercial operations date.

Results of Commercial Least-Cost Analysis: The comparison of commercial costs between CCGT and NT2 is less attractive to NT2.

The commercial cost of NT2 is calculated taking into account the project cost of USD 1185 million shown in Table 1 and Graph 3 above, the projected annual inflation of operational costs from 2009 onward, and the payment of taxes and royalties to GoL. The projected long-term levelized nominal commercial supply cost of electricity from NT2 will be about $ 0.041/kWh (Graph 6), added to which are $0.006/kWh for transmission within Thailand, yielding an aggregate long-term, levelized nominal delivered cost of about $ 0.047/kWh.

Graph 6. Structure of NT2 Commercial Cost (US cents/kWh)

(The vertical axis is US cents per kWh; GoL equity share is 25% of total equity)



To compare the commercial costs of NT2 and CCGT, the economic cost of CCGT energy (discussed above) is increased for taxes and inflation on capital as well as taxes and royalties on natural gas. The resulting forecast commercial CCGT cost is approximately US 4.6 cents per kWh. Hence, commercially the forecast costs of energy from these two sources are extremely close in the Thai power market. This also indicates that between NT2's economic cost and its commercial adjustments (equity returns to GoL and other sponsors, taxes and royalties to GoL and financing charges to lenders) nothing is projected to have been "left on the table" relative to the estimated cost of EGAT's option to use CCGTs instead. We explain the distribution of these costs and returns in Section [C].

As the costs of CCGT plant and natural gas may vary from the base case estimates discussed above, Graph 7 shows an array of CCGT capital and fuel cost combinations, indicating under which assumptions the estimated cost of NT2 is above or below that of CCGT plant, both operating at a plant factor of 74%.

Graph 7. Array of CCGT Commercial Capital and Operating Costs (USD/kWh)

fuel $/mm	Capacity Cost $mm per 100MW					
0.0460	35	40	45	50	53.66	60
2.25	0.0355	0.0368	0.0382	0.0395	0.0405	0.0422
2.50	0.0372	0.0386	0.0399	0.0413	0.0422	0.0439
2.75	0.0390	0.0403	0.0417	0.0430	0.0440	0.0457
3.00	0.0408	0.0421	0.0434	0.0448	0.0458	0.0475
3.25	0.0425	0.0439	0.0452	0.0465	0.0475	0.0492
3.50	0.0443	0.0456	0.0470	0.0483	0.0493	0.0510
4.00	0.0478	0.0492	0.0505	0.0518	0.0528	0.0545
4.50	0.0513	0.0527	0.0540	0.0554	0.0563	0.0580
4.75	0.0531	0.0544	0.0558	0.0571	0.0581	0.0598

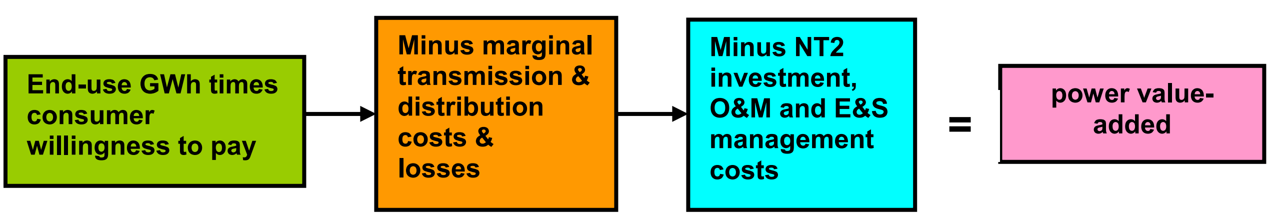
Yellow cell combinations: NT2 is cheaper

Notes to Graph 7: (i)"fuel $/mm" means fuel price per million British Thermal Units (btu). (ii) The more likely range of variation is bounded in the box covering the middle three rows and last four columns. (iii) The cell with heavy outlining is the base case estimate.

[B] Economic and Financial Rates of Return

Economic Rate of Return (ERR): The project's ERR measures the project's net economic benefits as illustrated below:

- **ERR = discount rate at which PV (benefits) – PV (costs) = 0**
- **THE ECONOMIC VALUE CHAIN IS:**



The gross benefit stream (green box) is the value of the electricity to end-users, as evidenced by the tariffs and VAT they now pay. In Thailand, the electricity tariff increased by about 5% earlier this year and the market has absorbed the increase at higher rates of consumption growth than anticipated, indicating Thai “consumer willingness to pay” is being sustained at a higher value than previously assumed. We use the current value for firm energy consumption (US cents 7.2/kWh at 40 THB/USD) and assume no future real increase, nor any "consumer surplus". Secondary energy does not add to consumption, but displaces thermal energy production, therefore it attracts a lower value equal at least to the variable cost of CCGT plant (US cents 2.5/kWh).

Lao willingness to pay is more tentative, as tariffs are now below economic and commercial cost recovery, and well below estimates of the value of electricity to Lao consumers.[14] An aggressive tariff adjustment program is underway, and its ultimate impact on demand remains to be seen. Nonetheless, for now, assuming that the cited willingness to pay estimates are plausible and therefore that the demand forecast will occur along with the tariff adjustments, we adopt the Government’s 2.3% per month tariff increase over 28 months in 2003-2005[15] resulting in a tariff increase from US cents 3.1/kWh at end 2002, to US cents 6.5/kWh (nominal) in 2005. This value is adjusted to the base year value of US cents 6.2/kWh (real), and assumed to be maintained at this level in real terms. There is no assumption of "consumer surplus."[16]

Concerning transmission/distribution costs and losses (orange box), **Thai system losses** for transmission and distribution are 7.1%. It is necessary to reduce the benefits of NT2 energy production by losses, because all power systems have transmission and distribution losses between the power plant and points of end-use, reducing end-use consumption relative to generation. Thailand’s loss rates indicate a power system operating at very high technical and commercial efficiency.[17]

Lao system losses are now about 16% (including technical and non-technical losses), but assumed to decline to 10% by 2009 as a result of power sector reform and increased investment in measures to improve commercial and technical efficiency.

Thai Distribution Costs are based on a forward projection of distribution system long-run average incremental cost (LRAIC) in Thailand. The Metropolitan Electricity Authority and the Provincial Electricity Authority provided their projections of incremental energy sales and investment programs over 2002 to 2011 and 2002 to 2008 respectively. To calculate the LRAIC of an investment, the incremental sales volume is stabilized at the value reached by the end of the expansion program and accounted over the number of additional years needed to complete a roughly 35 year economic life cycle for the incremental investments. The nominal investment values over the expansion phase are deflated to real THB levels using a projected THB CPI deflator of 2.8% per year then

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[14] Tariff Study, Vernstrom, Section 3.3

[15] This rate of tariff increase is expected to be adequate to bring tariffs to a commercially viable level including the effects of on-going inflation and currency devaluation as estimated in the Vernstrom Report.

[16] "Consumer surplus" is the difference between the actual tariff and what consumers would have been willing to pay for lesser quantities of energy up to the amount they consume at the actual tariff.

[17] Thailand has negligible non-technical losses and a fully commercial billing and collections profile.

converted to USD at THB 40/USD 1.[18] The present values (at 10% real discount rate) of the annual investment program are divided by the present values of the incremental GWh sales to end-users for the two systems, yielding an LRAIC of US cents 0.57/kWh. Recurrent operating costs of the incremental investments are based on the operational experience of 2001 plus a projection of long-term real productivity improvement of 1.5% per year for the next ten years[19], resulting in a real value of US cents 0.45/kWh. Combining investment and operating costs, the LRAIC of distribution is US cents 1.012/kWh. This value is multiplied by PE sales to end-users, resulting in total incremental distribution costs for NT2-associated sales.

For Lao PDR transmission Meritec-Lahmeyer provided a nominal cost estimate of USD 14 million per year for two years which we deflated to real dollars assuming that transmission works would begin two years before project commissioning. We assume, based on standard industry guidelines, that operating costs of the transmission line would be 1% of investment, and losses from the project to end-users 10%.[20] Project sales to the Lao system may range between 200 GWh and 300 GWh per year. We have used the upper estimate, resulting in end-use of 270 GWh, because the likely introduction of mining and other commercial loads in the off-take area may well use the full local allocation available from NT2.

Estimates of Lao LRAIC distribution costs are very tentative. The data covers the total national sales forecast from 2002 to 2010 and the total cost of the distribution investment program for new facilities. In light of the relatively low level of electrification in areas that the project will not likely serve and the large emphasis of the investment program on those areas, this data likely exaggerates incremental distribution costs for the areas more relevant to NT2. However, pending the availability of regional investment data, the national data are used here, which can be compared with those in the Vernstrom Tariff Study. We assume that distribution system incremental operating cost would be 3% of the cumulative investment costs. Combining the per kWh end-use cost of incremental transmission and distribution, the total of the two for Lao PDR is US cents 5.7/kWh. The economic issue for the power sector in Lao PDR is that the NT2 energy cost plus the projected incremental economic cost of transmission, distribution and losses exceed projected willingness to pay. Fortunately, this negative value-added affects only a very small share of NT2 energy. As well, this finding could well be reversed, if, for example, we find that we have over-stated relevant distribution costs and under-stated the eventual scope for tariff increases at the projected demand levels beyond 2005.

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[18] Based on experience of 1997 to 2001.

[19] The regulation of distribution tariffs includes an RPI-X formula. The actual values for X over the next ten years are not known; however, an assumption of 1.5% per year real productivity improvement over the next ten years is reasonable, especially in light of the scope for operational efficiency improvement being considered in the context of further sector reforms under discussion.

[20] We recognize that this loss ratio is lower than that in the Vernstrom tariff study. There are two reasons for this: (i) a tariff study needs to account for both technical and non-technical losses (NTL). An economic analysis only includes technical losses, because NTL is still consumption and part of consumer welfare, albeit not paid-for! The evolving size of NTL in response to increasing commercial discipline is uncertain. (ii) Technical losses could be limited to about 10% in light of the character of the future loads the project will serve.

NT2 economic costs are as defined in Section A above, and they include all incremental development, management, construction and E&S costs accounted to date.

The resulting range of project ERR estimates is shown here for a number of scenarios:

Scenario	ERR
1. Base Case	**17.1%**
2. Returns delayed one year	15.3%
3. 10% Project Cost Over-run	15.9%
4. Cases 2 & 3 combined	13.8%
5. Low Demand (a)	13.6%
6. Case 5 & 30% cost over-run	11.1%

(a) The low demand case assumes the project is not needed for the first three years, therefore only displaces the recurrent operating cost of thermal plant rather than catering to incremental demand.

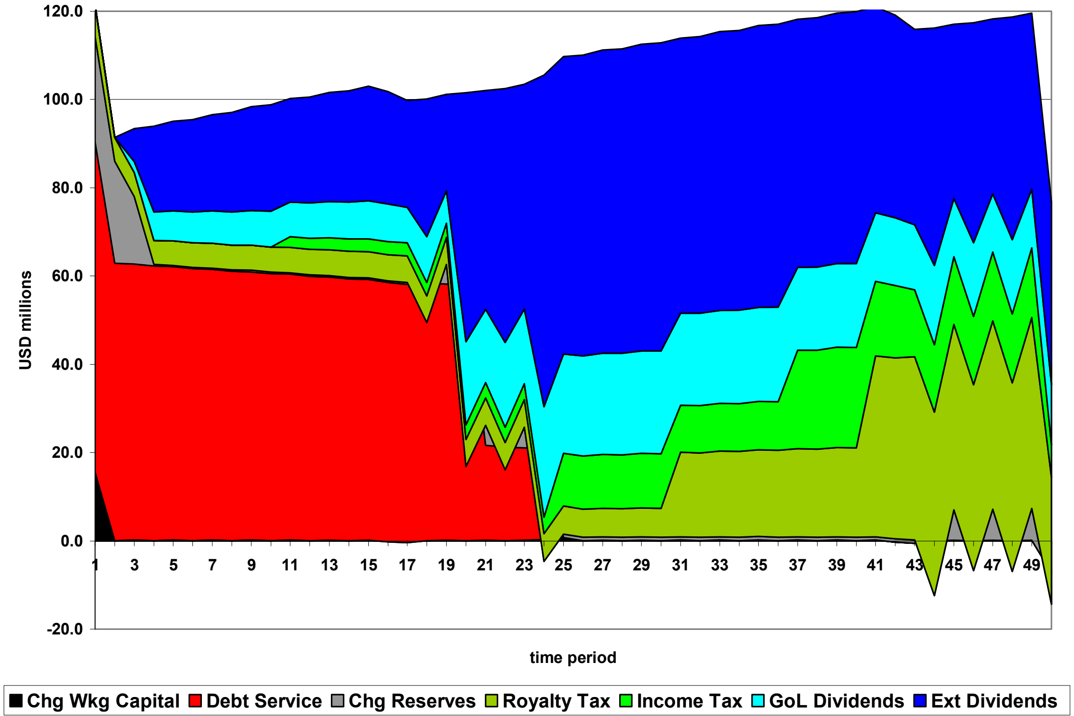
The results are tentative, as the sponsors have not completed several E&S impact studies and negotiation of the final head construction contract price, the outcome of which could increase or reduce the ERR estimates. To date, the results indicate that the NT2 project is an economic undertaking for the region as a whole.

Financial Rate of Return (FIRR): The project's base case internal financial rate of return to all capital employed is 14.4%. This result is calculated by the Bank, not the sponsors, based on the current version of the sponsors' financial model. The FIRR and the ERR discussed above are not comparable, because the benefit streams and some of the costs considered are completely different. In the FIRR, the benefit stream is the NT2 tariff revenue received by NTPC from EGAT for bulk power, while in the ERR it is end-user willingness to pay for electricity at point of end-use. Consistently, the FIRR excludes any consideration of transmission and distribution costs beyond the project boundary, whereas the ERR includes all costs of serving end-users.

[C] Distribution of Project Benefits

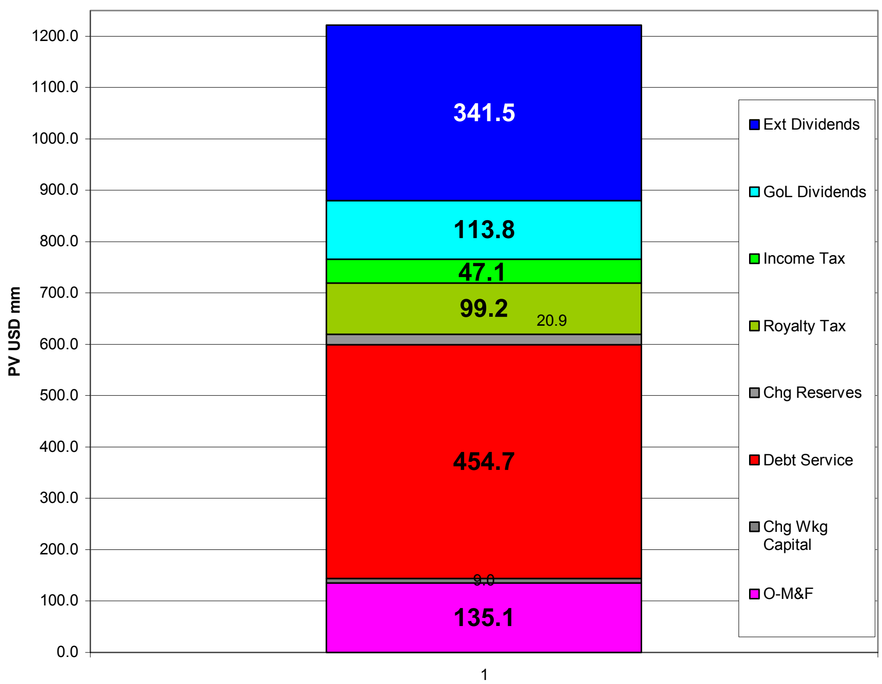
We mentioned at the end of Section A that NT2 provides returns to shareholders, the GoL treasury and lenders that combined with other project cash flows result in a projected commercial power cost similar to that of the CCGT alternative. This allocation of project cash flows is shown in Graphs 8, 9 and 10.

Graph 8. Structure of Cash Flow from Operations



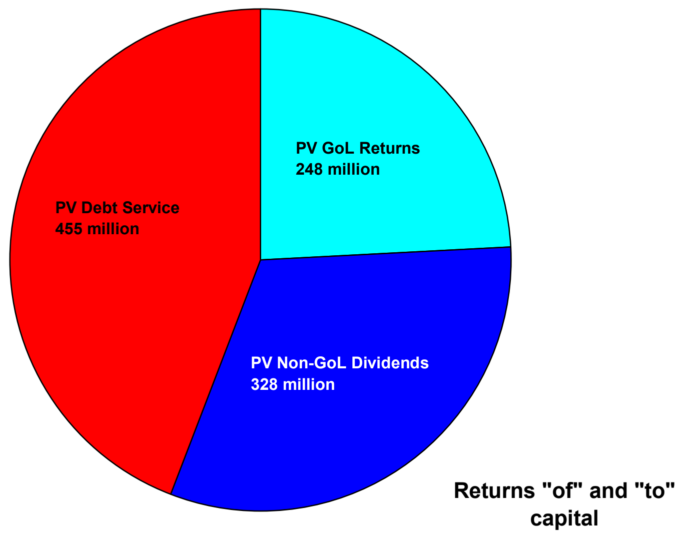
(Notes: (i) "Cash Flow from Operations" are payouts AFTER the project's operating costs have been paid, including the USD 60 million of recurrent E&S costs. (ii) The time periods are 6 month intervals from COD onward, except for period 1 which contains 8 months. (iii) Where cash flows dip below zero, this only means that the cash flow stack starts below zero in those years when there is a negative change in cash reserves permitted by operational requirements.)

Graph 9. Net Present Values of Cash Flow from Operations (Nominal)



(Note: in Graphs 9 and 10 the discount rate is 10% and the present value base date is January 2004. The values in Graph 9 are the present values of the streams in Graph 8.)

Graph 10. Present Value Returns (Real USD)



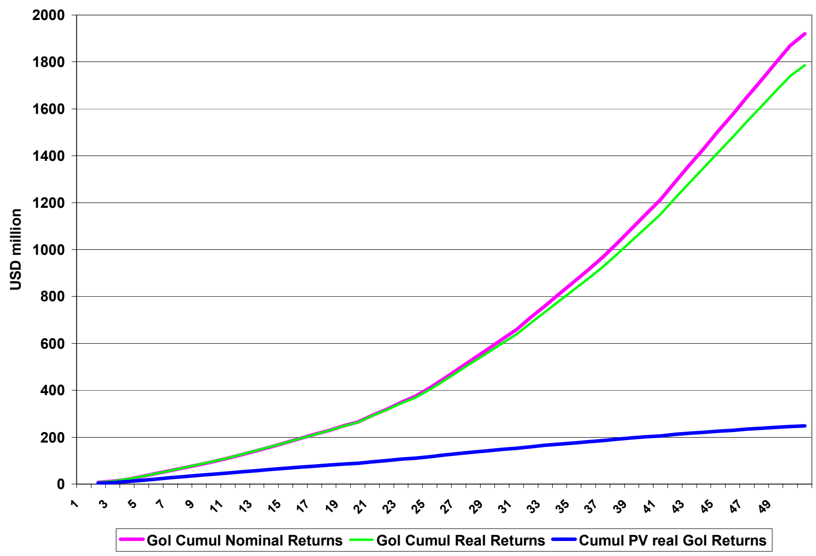
Graph 8 is the base case cash flow projection from the sponsors' financial model. Its main message is that equity returns to GoL and other shareholders are compressed during the first twelve years during which the commercial debt is repaid. Thereafter, dividends grow and are assumed – as usual - to be distributed in proportion to equity shares (75% external sponsors, 25% GoL). The rather low growth of total annual cash flow over the period of the PPA reflects the tariff structure, according to which the PPA tariff is rather uniform, subject only to a very low escalation rate from one period to the next.

Graph 9 mainly shows that debt service is the largest chunk of overall cash flow, reflecting the project's leverage of approximately 72% debt and 28% equity. Most of the remainder of the cash flow is distributed between taxes and dividends.

Graph 10 shows once again the prominence of the debt, but more importantly, that on a real present value basis, "GoL" total returns of USD 248 million (i.e. dividends, taxes and royalties to GoL) are about 75% of the value of the other sponsors' returns (USD 328 million). When one considers that (a) GoL is a 25% shareholder, (b) its returns of dividends, taxes and royalties, are over and above the USD 121 million of payouts to Lao PDR for E&S programs and compensation and (c) its returns to equity from dividends, taxes and royalties would be about 19%, it is reasonable to observe that GoL's share of the project's total value added is at least satisfactory. This finding is provisional pending conclusion of the outstanding E&S studies and completion of the head construction contract negotiations. For example, there could well be commercial and environmental benefits (and possibly some costs) arising from the availability of the access road, which are not yet included in this analysis.

We conclude the discussion of GoL returns distinguishing between the values discussed above and public information that GoL would earn almost USD 2 billion over the life of the PPA. The latter is correct cumulating all the nominal returns over the 25 year PPA. However, the foregoing discussion of present values is based on discounting each year's returns to present value and cumulating the present values. At a 10% discount rate, returns that are many years in the future have a very low present value. As a result, the present value of GoL returns, is in the range of USD 250 to 260 million depending on whether real or nominal. These relationships between cumulative real discounted returns and undiscounted nominal and real returns are shown in Graph 11. We remind that this benefit stream is confined to the duration of the PPA. Well managed, the NT2 hydropower project should remain a productive power generating facility for decades after the end of the current PPA.

Graph 11. GoL Cumulative Returns



Based on the most recent analysis carried out by the World Bank, the nominal annual GOL NT2 revenues during the first ten years of operations are expected to be less than five percent of total GOL revenues each year, because of the heavy back-loading of GOL revenues from the project.

[D] Summary of Economic Analysis Findings:

- NT2 is economic because it forms part of a least-cost system expansion program for Thailand and Laos by the earliest feasible commissioning date, and because its ERR is satisfactory. These results are robust to a considerable range of downside risks.

- From a commercial perspective, NT2 is projected to be just about competitive with CCGT plants in Thailand, indicating that between dividends, taxes and royalties, all the project's value-added has been fully allocated with nothing to spare.

- The project's economic internal rate of return is satisfactory.

- The distribution of returns between GoL and the other sponsors seems reasonable.
- All of these results may be modified once the final capital and operating costs of the project are known and their results included in the analyses.

(August 21, 2004)