6.3.2 CONFIRMATION OF BASIC PARAMETERS

(1) Watershed and Streams

The watershed of the Nam Ngiep River is developed north to south. The maximum width of the basin (west to east, NL103°02'to NL103°44') is 180km and the length (north to south, NE 19°25' to NE 18°39') is 230km. The Nam Ngiep River flows down in the densely forested area for a distance between its origin the Khe Mountain with its peak EL.2,125m and the Mekong flood plain with EL.160m. The upper half stretch runs in the central part of the basin and the lower half passes through the left side (eastside) of the basin.

The Nam Ngiep River collects water from own drainage basin and her 13 tributaries: (i) Nam Sen, (ii) Nam Siam, (iii) Nam Thong, (vi) Nam Pong, (v) Nam Chian, (vi) Nam Hok, (vii) Nam Mang, (viii) Nam Phouan, (ix) Nam Gnok, (x) Nam Sau, (xi) Nam Kasa, (xii) Nam Tak, (xiii) Nam Xao. Profile of the Nam Ngiep River is divided into five (5) sections with an average river inclination as given below:

Table 6.3.1 Division of Nam Ngiep River Slopes

No.	Nam Ngiep River Section	River Slope
1.	175km to 110km upstream of dam site	1:90
2.	110km to 95km upstream of dam site	1:40
3.	95km to 75km upstream of dam site	1:250
4.	75km upstream to dam site (0km)	1:650
5.	Dam site (0km) to Mekong confluence (-55km)	1:3,800

(2) Determination of Dam Site

Out of the proposed dam site, there are two (2) major gorges suitable for the site on the Nam Ngiep River at 20km and 40km upstream as shown in Figure 6.3.1. The following are the topographic characteristics of the respective gorge as the site for a 180m-class high dam:

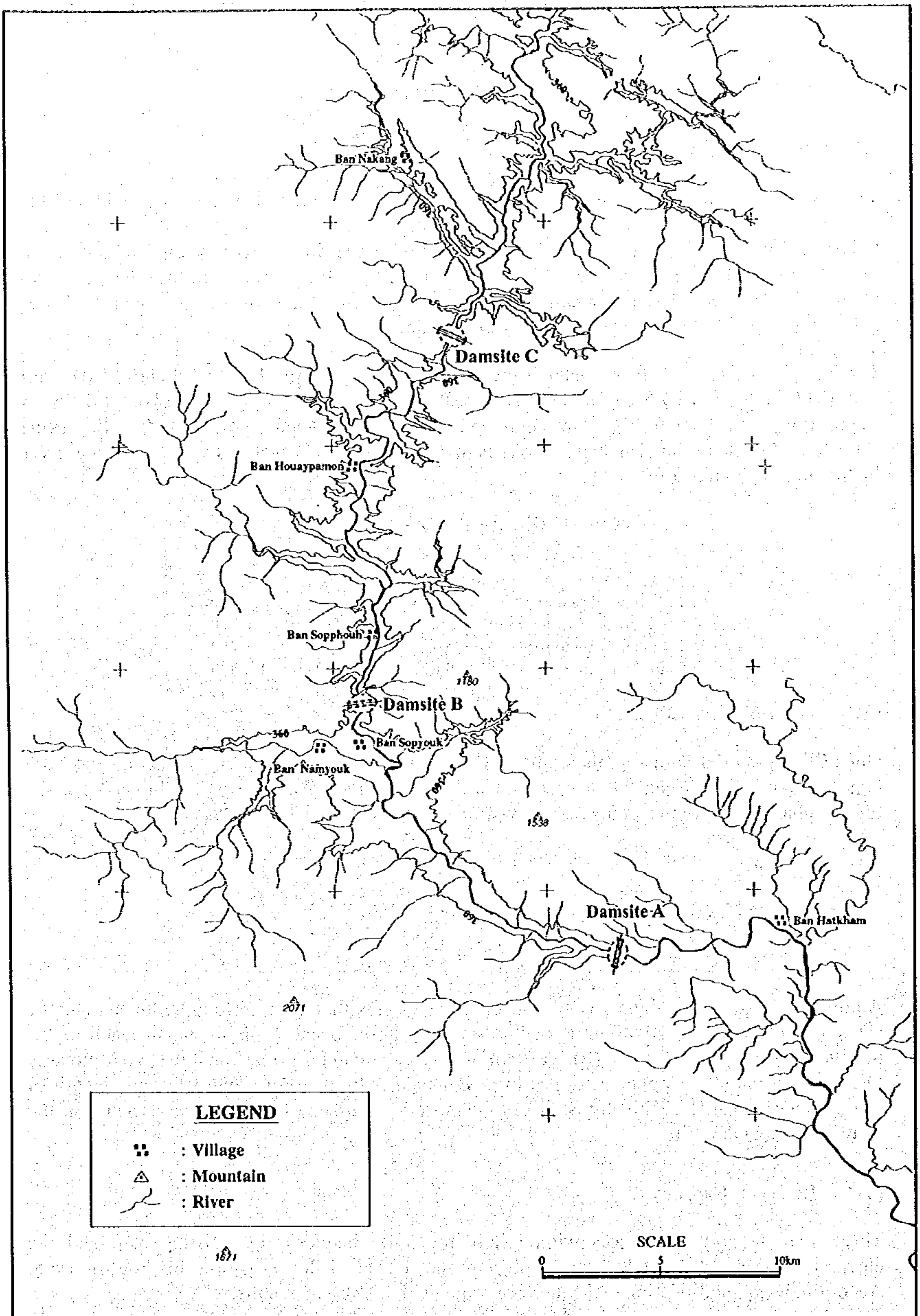
Table 6.3.2 Topographic Conditions at 3-Alternative Dam Sites

Site	Riverbed	Dam Crest Length
A (Proposed dam site)	EL.180m	630m
B (20km upstream from A)	EL.230m	1,100m
C (40km upstream from A)	EL.270m	530m

Among the above, topographic condition of Site-C seems the most preferable, but its storage capacity will decrease to two-thirds of the same at Site-A, because the upstream reach of the reservoir is steep as 1 (H) to 40 (L). A 30km long access road has to be constructed additionally to Site-C on the steep mountain slopes from B.Thahua. Furthermore, the dam crest length of Site-B is more than 1km. Finally, Site-A at the most downstream of the river was selected as the recommendable dam site.

(3) Reservoir Capacity

There were notably differences without any regularity between the existing map and the elevations measured by GPS survey during the 1st Field Investigation in August 1998. Accordingly, no modification to the map was done with the survey results.



FEASIBILITY STUDY ON THE NAM NGIEP-1 HYDROELECTRIC POWER PROJECT IN THE LAO PEOPLE'S DEMOCRATIC REPUBLIC	Figure 6.3.1
JAPAN INTERNATIONAL COOPERATION AGENCY	Alternative Damsites on Nam Ngiep River

As the revised map had been prepared based on the result of the topographic survey made during the 3rd Field Investigation in February 1999, it was compared with the existing map of 1:50,000 Scale. As a result, it was revealed that the upper reservoir area is about 5% narrower than that measured by the existing map. Therefore, the upper reservoir area and capacity were reduced and the Area-Capacity Curve was modified as shown in Figure 6.3.2.

It was confirmed by the ground survey at the Thaviang Sub-District that the difference was large, about 5% of the total reservoir capacity, for only 20% of the total reservoir area. Therefore, the necessity of an aerial photo survey has increased for the entire reservoir area at the next stage. As well, attention should be paid to accuracy in the economic evaluation on the medium-dam development scale, which is susceptible to the storage capacity.

Table 6.3.3 Modification of Storage Capacity based on Survey Results at Thaviang Sub-District

EL.	Area at Thaviang (km^2)			Total Reservoir Area		Reservoir Capacity (mil. m^3)			
(m)	on Map	by Survey	Balance	on Map	Modified	Deduction	on Map	Modified	Rate(%)
300	4.51	0.00	4.51	45.00	40.49	45.6	1,181.0	1,135.4	96.1
320	12.04	4.45	7.59	81.50	73.91	166.6	2,446.0	2,279.4	93.2
340	19.98	14.02	5.96	120.00	114.04	302.1	4,461.0	4,158.9	93.2
360	28.41	20.63	7.78	156.00	148.22	439.5	7,221.0	6,781.5	93.9
380	36.92	28.87	8.05	198.00	189.95	597.8	10,761.0	10,163.2	94.4
400	45.31	36.98	8.33	240.00	231.67	761.6	15,141.0	14,379.4	95.0

(4) Study on Sediment

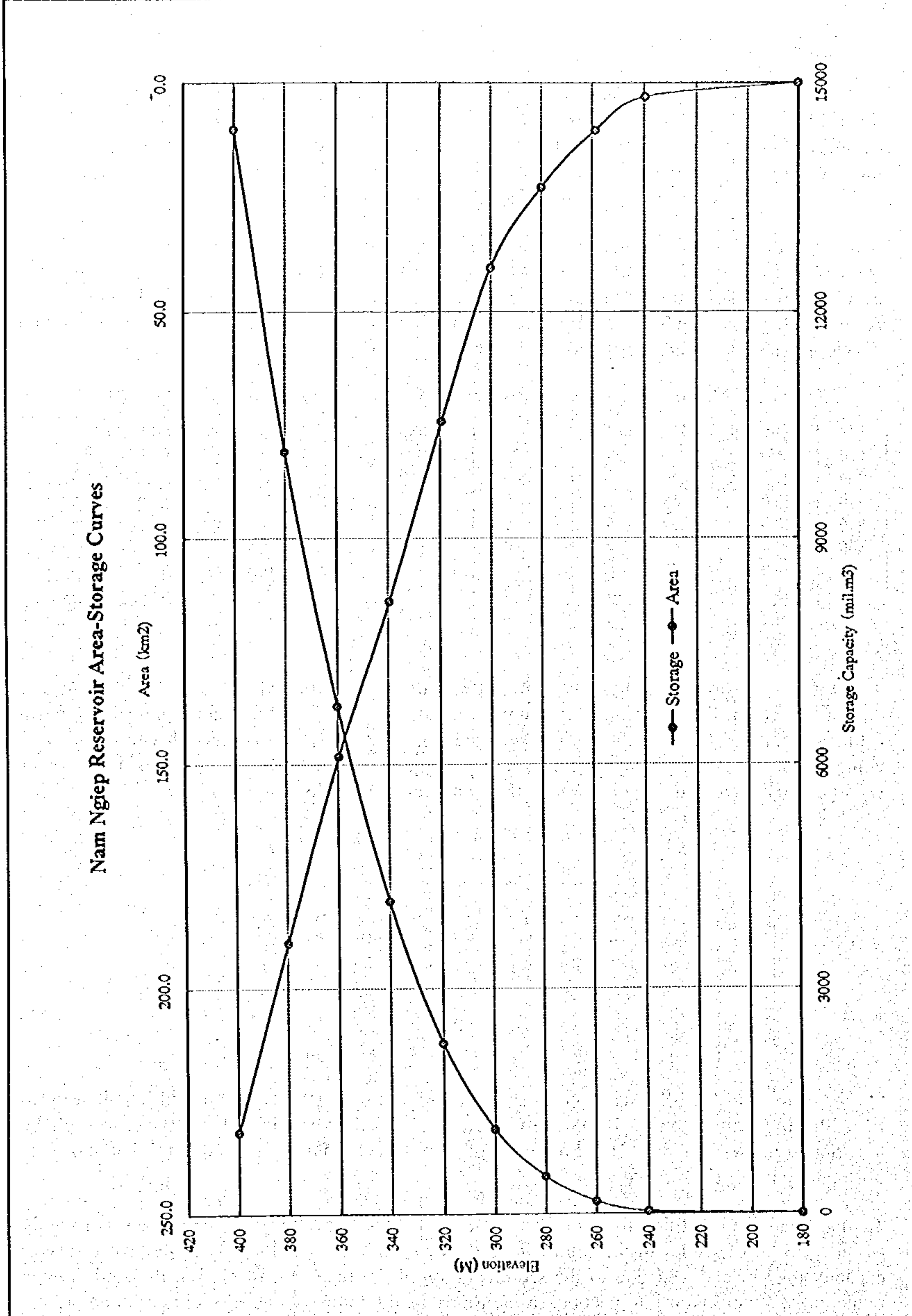
To set up a provisional Minimum Operation Level of the reservoir (MOL), sediment volume and sediment level in the reservoir was studied. Sediment yields for the Nam Ngiep River basin estimated in the "Study of Alternatives" on Nam Theun-2 HEPP was adopted, because the value computed in the above study is conservative compared with the figure assumed in the other report and the yield actually observed in the Nam Ngum-1 HEPP watershed.

Table 6.3.4 Estimate of Sediment Volume

No.	Items	Applied Value
1.	Nam Ngiep basin area, A	3,700 km^2
2.	Sediment equation established by NT-2	Sed_{spec} ($t/km^2/year$) = $448.8A^{-0.01}$
3.	Computed unit sediment rate	413.4 $t/km^2/year$
4.	Specific gravity of sediment	2.65 t/m^3
5.	Density in appearance	1.59 t/m^3
6.	Trap ratio	90%
7.	Void ratio of sediment in reservoir	40%
8.	Cumulative sediment volume in 100 year	87 mil. m^3

On the Reservoir Area-Storage Curves shown in Figure 6.3.2, the reservoir will be filled up to EL.240m by sedimentation, if 100% of the above cumulative sediment in 100 years will be transported to the dam site. However, most of the sediment may be trapped at the flat and wide upstream reach of the reservoir.

Taking the above condition into consideration, the sediment level near the dam site was roughly assumed to be EL.200m in the Study of MOL for reservoir operation. The effective reservoir capacity may be reduced due to the sedimentation at the upstream reach, but the said storage reduction was not taken into account in the Study as the total volume of sediment is negligible small compared with the total effective capacity of the reservoir.



FEASIBILITY STUDY ON THE NAM NGIEP-I HYDROELECTRIC POWER PROJECT IN THE LAO PEOPLE'S DEMOCRATIC REPUBLIC	**Figure 6.3.2** **Area Capacity Curve of Nam Ngiep Reservoir**
JAPAN INTERNATIONAL COOPERATION AGENCY	

(5) Limitation at Scale of Reservoir

The Nam Sau River is a left bank tributary which joins with the Nam Ngiep River at 11km upstream of dam site. As shown in Figure 6.3.3, its origin is located at a saddle having the altitude of EL.390m. The maximum FSL of the Nam Ngiep reservoir will be subject to the elevation of the said saddle, because the opposite side of the saddle inclines to the Nam Xan River.

The maximum FSL to be studied is, therefore, topographically limited to a practical EL.400m with the construction of a 15m high auxiliary dam along the saddle to be built on the prospective foundation around 5m below the ground surface.

(6) Inundation at the Thaviang Sub-District

As shown in Figure 6.3.4, the possible maximum reservoir level of EL.400m will reach to 95km upstream of the dam site, within which there exist 18 villages in total.

During the 3rd Field Investigation, a land-leveling survey was carried out at the upper reservoir area, the Thavian Sub-District, to grasp actual extent and elevations of paddy lands and the number of villages. As a result, their extent was made clear for the different altitudes between EL.320m and EL.380m at 20m intervals, and it was revealed that most of the villages and paddy fields in the Thaviang Sub-District is released from inundation, if FSL is lower than EL.320m. The area of paddy fields and population below EL.320m belongs to the Hom District.

Confirmed areas of cultivating lands and the number of villages to be inundated at the respective elevation are as shown below:

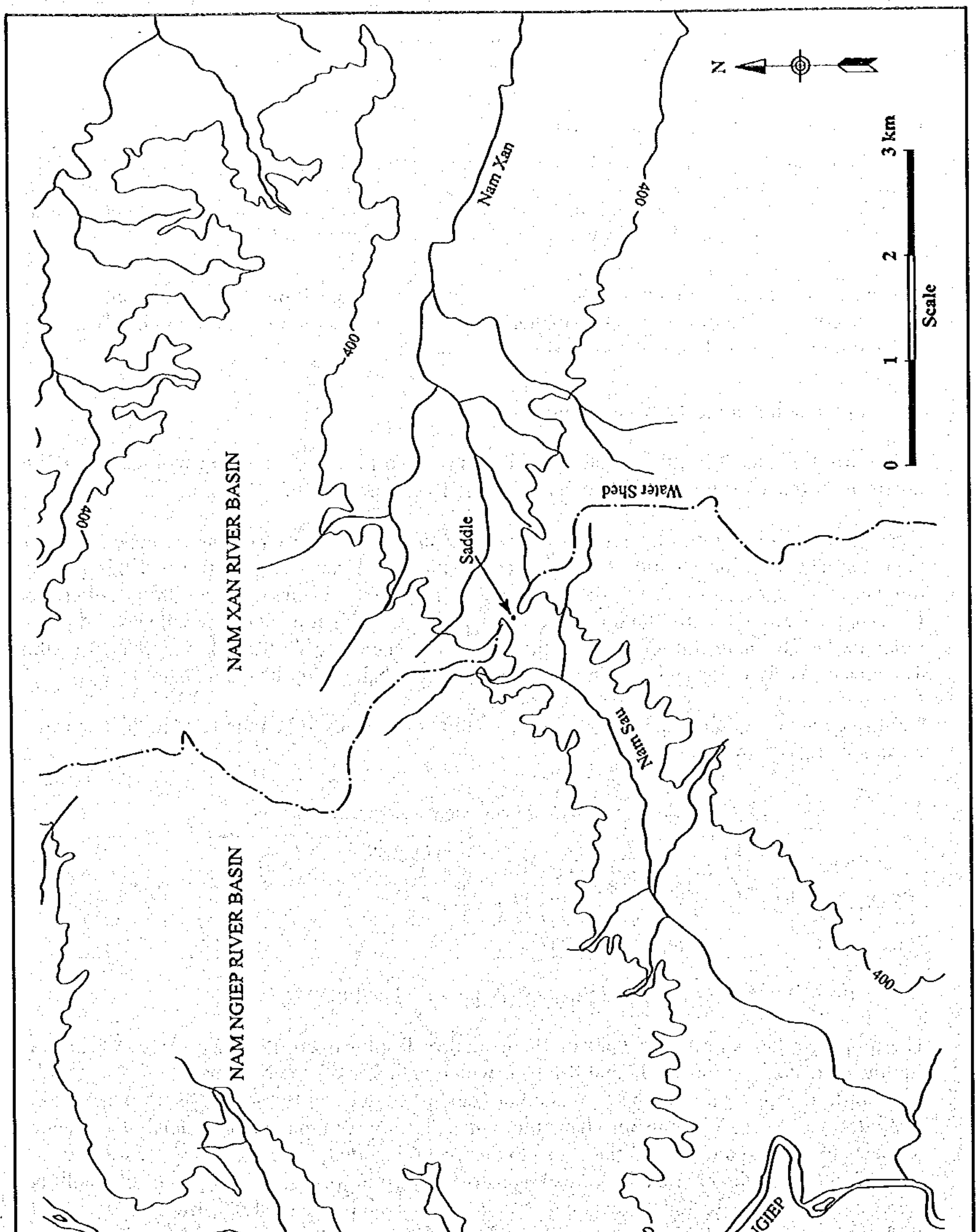
Table 6.3.5 States of Inundation at Respective Elevation

Particular	FSLs of Proposed Reservoir				
	EL.240m	EL.320m	EL.340m	EL.360m	EL.380m
Paddy Field (ha)	0 (0%)	216 (29%)	642 (86%)	709 (95%)	746 (100%)
Dry Field (ha)	0 (0%)	96 (27%)	252 (71%)	312 (88%)	355 (100%)
Village (no.)	0 (0%)	5 (28%)	13 (72%)	15 (83%)	18 (100%)

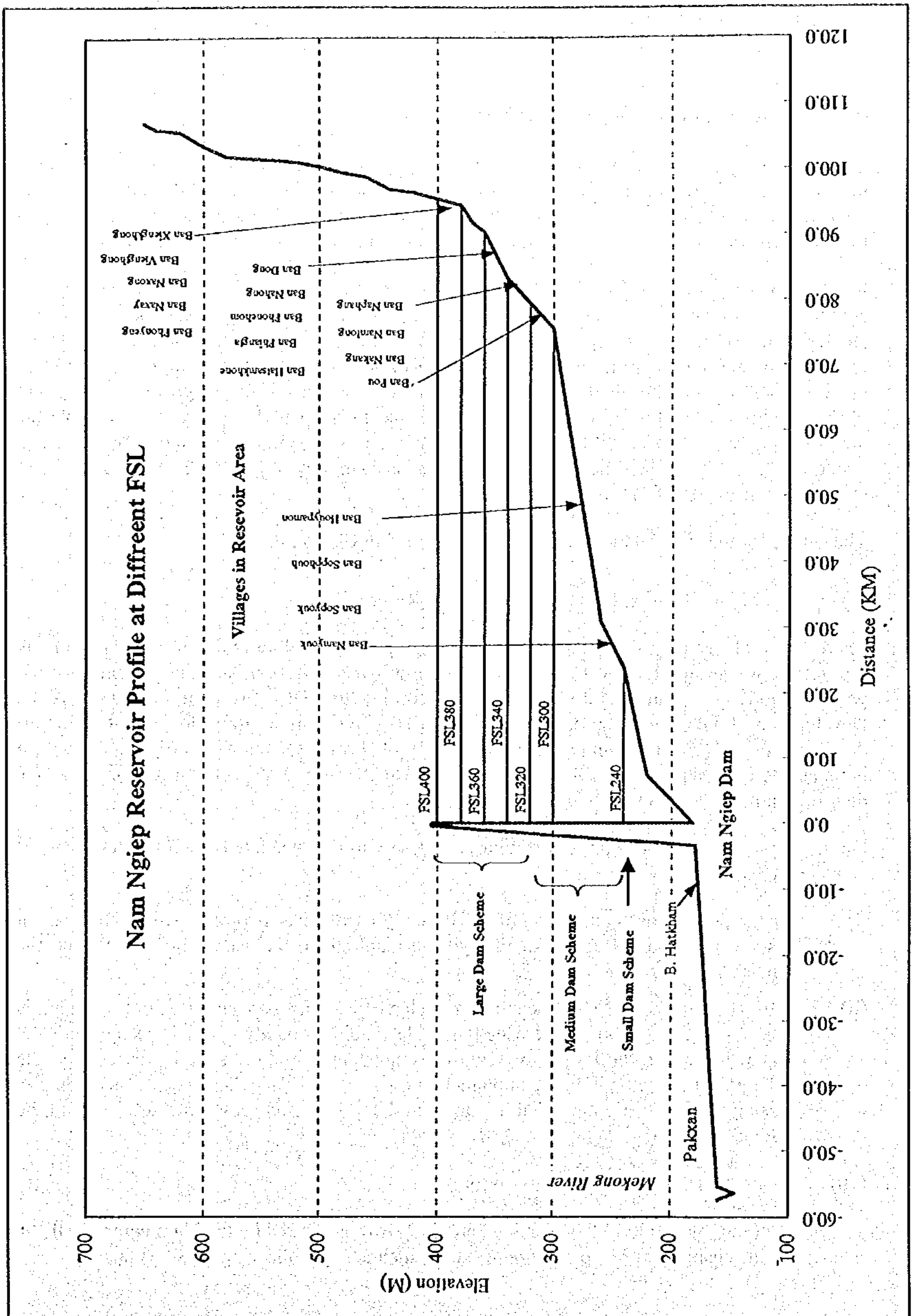
(7) Route for Access Road and Sites for Temporary Facilities

The proposed dam site is near Pakxan, the capital of Bolikhamxay Province. Between Pakxan and the dam site, there is a National Route-4, which branches off the National Route-1. Route-4 runs north to approaching to the dam site but goes off by turning to the east at Borikhan, 20km away from Pakxan. From Borikhan, there is a narrow non-paved provincial road, which connects to B.Hatkham. When the Project construction started, betterment of the road between Pakxan and B.Hatkham and new road construction from B.Hatkham to dam site will be, therefore, required. As for the existing road conditions and new road construction, details are explained in Chapter 8.

Major construction temporary facilities will be located downstream of the main dam site. There are three (3) flatter areas between the main dam site and re-regulation weir site along the Nam Ngiep River. At these sites, contractor's offices and residential quarters and other workshop buildings (warehouses, motor pool, repair-shop, concrete plant, etc.) will be constructed.



FEASIBILITY STUDY ON THE NAM NGIEP-1 HYDROELECTRIC POWER PROJECT IN THE LAO PEOPLE'S DEMOCRATIC REPUBLIC	Figure 6.3.3 **Topographic Limitation for FSL**
JAPAN INTERNATIONAL COOPERATION AGENCY	



FEASIBILITY STUDY ON THE NAM NGIEP-1 HYDROELECTRIC POWER PROJECT IN THE LAO PEOPLE'S DEMOCRATIC REPUBLIC	**Figure 6.3.4**
JAPAN INTERNATIONAL COOPERATION AGENCY	**Reservoir Profile at Difference FSL**

(8) Study on Re-regulation System for D/S Reach

The maximum discharge from the Nam Ngiep power plant will be about 220m^3/s. According to the operation rule required by EGAT, power generation will be interrupted daily for several hours and entirely on Sunday and Thai national holidays. On the above condition, water level of the downstream reach will fluctuate largely with dangerous ranges to the riparian people.

For the downstream water level fluctuation, there are several ordinary and rather economical countermeasures such as installation of a river alarm system, river protection works, etc. However, it was judged indispensable to provide a re-regulation function at the downstream reach taking into consideration that the impact to the downstream stretch might be extremely large by such intermittent plant operations as (i) the Project aims at power generation only, but further study is needed, (ii) plant is operated 2/3 and interrupted 1/3 every day, and (iii) the downstream water release will be stopped entirely every week and on national holidays. As a result, the re-regulation facilities will be constructed at 5km downstream of the main dam site to regulate the discharges from the powerhouse.

The details for the re-regulation facilities are explained in Chapter 8.

(9) Rural Electrification Plan around Proposed Reservoir Area

There is a rural electrification plan to extend a 115kV power distribution line from the Nam Leuk P.S. to Phonsavan through the Hom District: the lower reservoir area and the Thatom District, which includes the Thaviang Sub-District. According to EDL, this plan funded by Asian Development Bank has been consolidated by EDL and it is waiting for the decision of development scale for the Nam Ngiep-1 HEPP for a final route selection. As of August 1999, it is under the Pre-Qualification for the future ICB in September. Prospective route of the above distribution line is as shown in Figure 6.3.5.

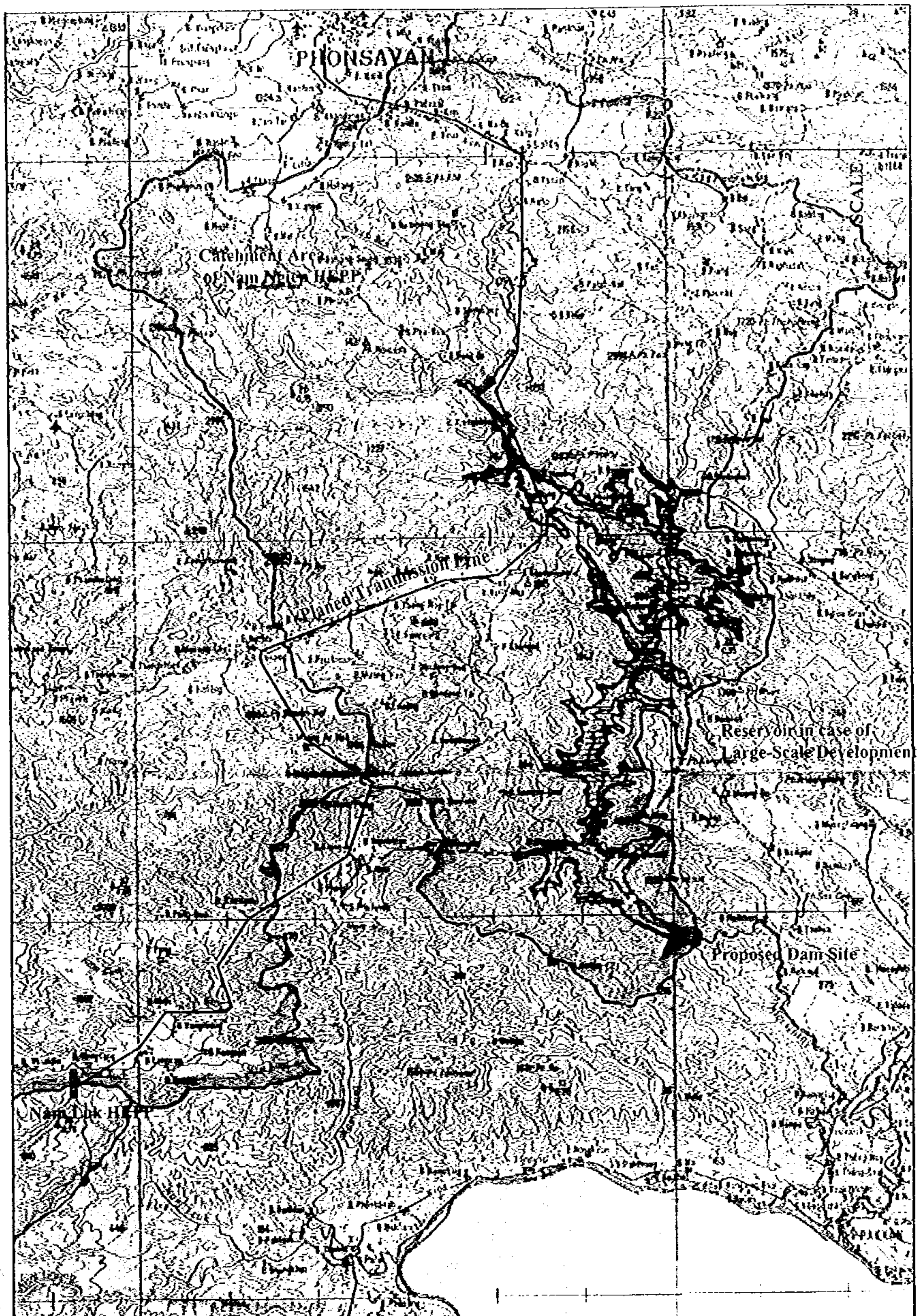
On the above circumstance, the following are necessary to be considered when the development is made on a large scale:

(i) For the period until completion of the Project, resettlement is prospected for 10 years at least, so a temporary power supply will be required for the Thaviang Sub-District, the same as the other beneficiaries.

(ii) If the Thaviang Sub-District benefits from electrification, a concentration of population is foreseen for this region, where wide flat land suitable for paddy field has been developed. That will force to the Project review of resettlement plan due to the increase of people and area to be resettled. In the implementation of a large-scale dam scheme, accordingly, legislation for restriction of migration to the prospective reservoir area should be provided at an early stage.

(10) Application of Generating Peak Hours

The first electric sales to EGAT in Thailand are the power generated by the Nam Ngum 1 HEPP. At present, the electricity price per kw-hour (tariff) includes the following three (3) rates:



FEASIBILITY STUDY ON THE NAM NGIEP-1 HYDROELECTRIC POWER PROJECT IN THE LAO PEOPLE'S DEMOCRATIC REPUBLIC	Figure 6.3.5 Rural Electrification Plan
JAPAN INTERNATIONAL COOPERATION AGENCY	

Table 6.3.6 Electricity Price (Tariff) of Nam Ngum 1 HEPP

Items	Peak Time	Partial Peak Time	Off-Peak Time	Weighted Average
Time	18:30-21:30	08:00-18:30	21:30-08:00	00:00-24:00
Duration	3.0 hrs	10.5 hrs	10.5 hrs	24 hrs
Tariff	5.78 US cents	3.75	3.00	3.676

At the Theun-Hinboun HEPP of which commercial operation commenced in April 1998, though a power generation was planned to operate 24 hours with a flat rate tariff in PPA, actual operation is subject to the EGAT's daily requirement. The planned Nam Theun 2 HEPP had conducted with PPA to operate 24 hours, but, it was changed to generate additionally with an intermediate peaking basis over 16 hours a day by using a stand-by generator due to the EGAT's requirement. Also, EGAT has proposed a new arrangement for electricity purchase from the Nam Leuk HEPP (to be completed at the end of 1999) with a 6-hour peaking basis for the peak demand in Thailand.

The power demand in Thailand was lower than the previous year in 1998, but, daily peak demand is trending sharp year by year. Consequently, it is expected for EGAT to require in the near future power purchase from Lao PDR for peak demand.

However, since EGAT requires most IPPs in Lao PDR to purchase the Intermediate Peaking Power for the time being, the same Intermediate Peaking Power for 16-hour is applied at this moment for the study of the Nam Ngiep-1 HEPP. The Nam Ngiep-1 HEPP becomes drastically attractive if EGAT accepts 8-hour peaking operation in the future.

(11) Discharge for Power Generation

The series of river run-off for power output calculation was applied to the Study, which were provided for the Nam Ngiep River basin in the "Study of Alternatives" of the Nam Theun 2 HEPP as explained in Chapter 4. This run-off series consists of the long-term monthly mean discharge for 30 years. The average discharge is 162.3m^3/s, which is only 77% of 210.8m^3/s adopted in the Pre-F/S Report. The inflow duration curve for 30 years at the proposed dam site is as follows:

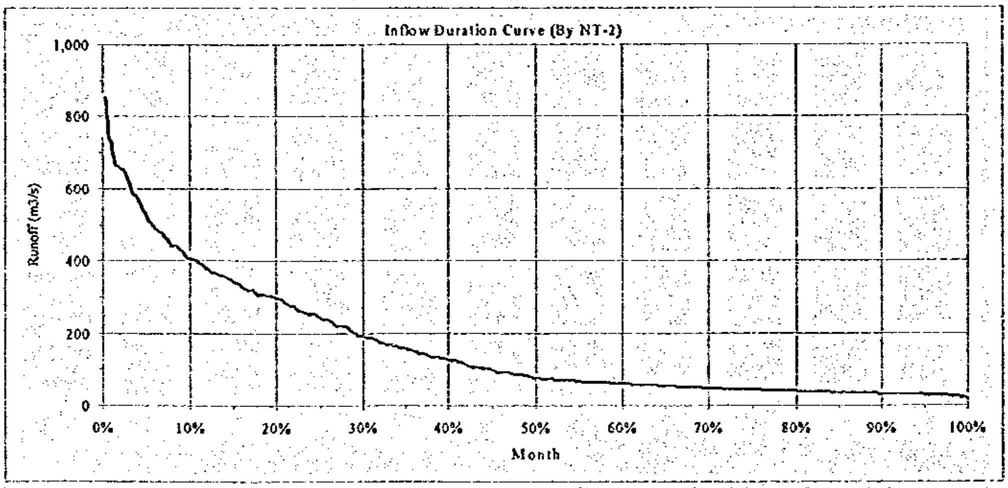


Figure 6.3.6 Duration Curve for 30 Years at Dam Site

Table 6.3.7 Monthly Discharge (m^3/s) on the Nam Ngiep River at Dam Site (NT-2 Generated Series)

Year	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Ave.
1966	39.7	33.8	31.3	30.0	79.1	275.4	531.2	766.8	540.0	234.7	117.1	62.3	229.9
1967	48.6	39.9	34.8	32.5	42.5	157.9	329.2	298.5	504.5	232.9	114.1	65.7	158.9
1968	50.0	43.4	39.1	36.3	70.5	189.5	218.6	400.2	379.3	179.6	89.1	56.7	146.7
1969	48.4	42.2	37.0	34.7	47.6	301.8	551.6	665.7	244.4	120.0	75.3	51.8	186.5
1970	44.8	39.4	35.6	32.3	81.6	303.8	462.8	660.3	654.0	278.7	109.4	56.7	231.0
1971	40.3	32.7	29.6	27.4	64.3	143.2	360.4	481.0	371.3	174.7	100.1	62.5	158.3
1972	43.4	35.1	32.0	30.8	48.0	121.6	360.4	737.3	428.1	192.8	108.5	69.8	185.4
1973	49.0	42.6	38.0	34.3	29.8	122.7	362.0	510.5	718.3	306.1	137.3	72.3	202.7
1974	59.9	50.8	44.6	41.6	54.0	147.2	220.7	341.1	390.9	186.0	102.6	59.5	142.0
1975	51.3	41.6	37.5	32.8	64.5	186.6	252.7	605.1	615.8	265.9	130.3	72.9	197.2
1976	60.3	52.5	43.1	39.5	57.7	149.4	295.0	392.5	306.6	149.9	102.6	73.3	144.4
1977	58.1	49.4	43.2	39.1	61.1	70.3	281.6	306.3	284.3	142.4	72.7	47.0	121.9
1978	39.9	35.2	32.3	31.4	64.2	261.9	474.3	653.2	481.7	214.7	97.3	55.7	204.7
1979	45.7	40.0	34.7	30.9	101.1	183.2	204.4	409.4	328.0	158.5	84.6	55.4	140.3
1980	47.4	37.7	34.7	32.5	60.9	159.9	443.0	366.9	442.2	205.8	102.1	62.3	167.2
1981	52.6	45.3	38.3	36.1	76.1	253.4	663.5	582.1	489.2	218.9	131.8	70.7	222.9
1982	58.7	49.9	43.1	39.5	68.1	185.4	235.5	580.8	357.9	167.6	105.6	65.4	164.0
1983	54.2	43.2	37.5	34.1	64.4	104.3	295.4	406.2	318.6	154.6	92.6	57.4	139.3
1984	43.2	38.2	33.1	30.7	62.7	133.5	408.1	459.4	322.6	155.3	91.0	59.5	154.3
1985	50.7	44.3	38.0	32.2	68.2	166.3	275.2	405.3	348.2	166.9	85.1	56.2	145.4
1986	39.3	31.1	27.6	26.7	134.6	293.1	395.9	305.7	247.5	126.4	69.7	46.3	146.1
1987	81.9	67.7	56.2	53.4	54.2	131.6	193.9	338.4	165.2	90.6	60.4	45.2	112.0
1988	28.6	23.4	20.5	20.0	61.8	84.4	202.8	320.1	163.1	132.1	79.6	44.5	99.2
1989	36.1	30.2	27.3	30.8	70.1	237.4	262.2	315.6	255.1	193.2	93.2	58.2	134.7
1990	41.7	34.2	34.3	26.7	92.2	239.6	379.2	351.8	252.6	141.7	85.8	58.3	145.7
1991	43.3	33.4	28.1	30.0	33.2	120.8	259.2	426.6	299.2	130.1	74.6	53.2	128.4
1992	45.9	35.3	29.6	24.3	27.9	71.5	219.3	251.2	173.4	91.7	50.5	40.5	89.0
1993	31.0	26.6	23.4	25.4	63.7	169.6	437.3	351.2	367.5	130.8	73.8	49.1	146.6
1994	36.7	33.4	35.8	40.1	91.0	338.6	442.1	850.4	564.1	222.9	121.8	64.4	238.1
1995	54.1	46.5	41.3	37.2	62.7	158.7	318.7	632.3	499.0	221.6	101.2	58.4	187.0
Average	47.5	40.0	35.4	33.1	65.3	182.1	344.5	472.4	383.8	179.6	95.3	58.4	162.3

6.3.3 COMPARATIVE DAM SCHEME AND LAYOUT

(1) Alternative Schemes and Sequence of Study

Alternative dam type schemes were studied by changing operational range of reservoir to evaluate the different impacts at the upstream and downstream areas of proposed reservoir and the downstream of the dam site based on the IEE survey results.

The alternative study was executed with two (2) phases. In the first phase, three (3) development scales, large, medium and small, were selected changing the Full Supply Level of the reservoir (FSL). The large scale was defined as the schemes to maximize power generation by increasing FSL as high as possible by which all villages in Hom District and most of the villages in Thaviang Sub-District will be inundated. On the other hand, the small scale was defined as the schemes to develop hydropower without inundation of any villages. The medium scale was therefore interpreted as the schemes to be developed with the scales between large and small.

At the second phase, the detailed alternative study was performed for FSLs between EL.300m and EL.390m at 10m intervals except the small-scale scheme, which had been rejected in the 1st phase. In addition, social and natural environmental assessment was also carried out for each FSL.

Definitions of the alternative scale-boundary made in the 1st phase are shown below:

Table 6.3.8 Configuration of Dam Type Alternatives (1st Phase)

No.	Alternative Plans	Description
1.	Large-scale dam scheme	The scheme aiming to a large power output by a high dam. Reservoir of the scheme will inundate all villages. Possible FSL ranges from EL.360m to EL.400m.
2.	Medium-scale dam scheme	The scheme with a medium-scale dam considering the minimization of impacts by the development. Possible FSL ranges from EL.240m to EL.360m.
3.	Small-scale dam scheme	The scheme to be developed with a small-scale dam taking no inundation of villages into consideration. Possible FSL is at EL.240m.

(2) 1st Economic Comparison Result

An economic-optimum development scheme of the Project is defined to maximize the benefit and internal rate of return computed for the comparative types and scales of the development. Detail of the economic analysis is as given in Chapter 6.5. The summary of the comparative economic aspects of the respective scale is as shown below:

Table 6.3.9 1st Economic Comparison of Alternative Dam Type Schemes

No.	Particular	Unit	Small-Scale FSL EL.240m	Medium-Scale FSL EL.310m	Large-Scale FSL EL.360m
1.	Installed capacity	MW	17	246	377
2.	Total energy production	GWh	124	1,375	1,983
3.	Project construction cost	Mil.US$	233.2	409.2	576.9
4.	B	Mil.US$	-	392.3	584.2
5.		Mil.US$	-	307.2	433.0
6.	B/C	-	0.18	1.28	1.35
7.	B-C	Mil.US$	-143.5	85.1	151.2
8.	EIRR	%	0.0	13.2	14.0

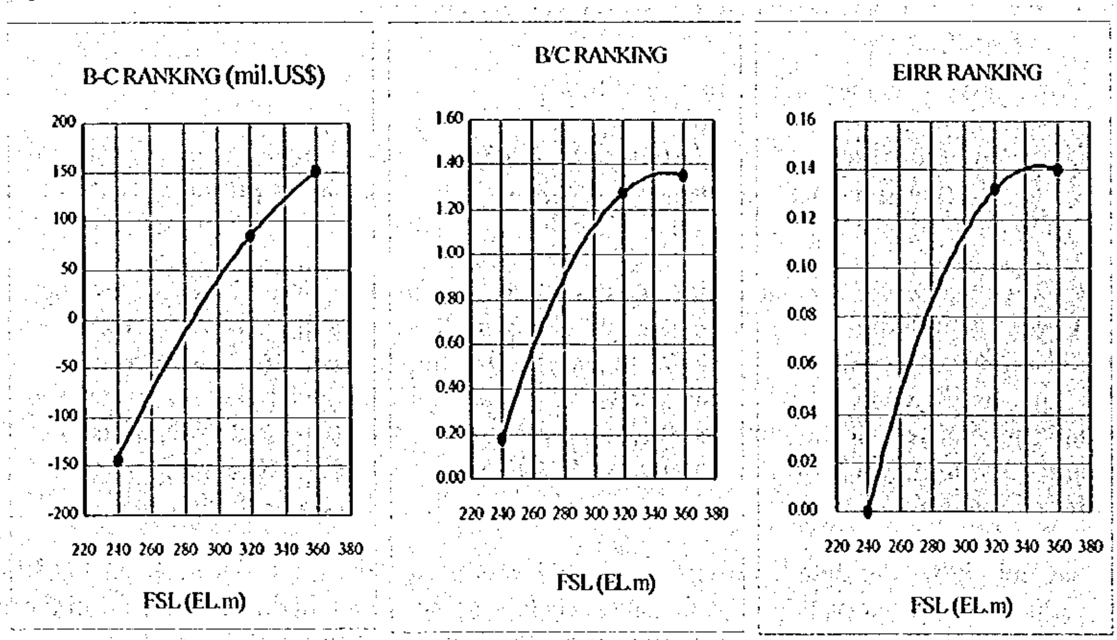


Figure 6.3.7 Results of 1st Economic Comparison

The results manifested the following:

(i) The small-scale dam scheme is not justified from the economic viewpoint.

(ii) Even in the medium-scale dam scheme, FSLs lower than EL.300m do not seem to be economical B/C<1 and EIRR<0.1 as shown in Figure 6.3.7 above.

(iii) Project viability of the large-scale dam scheme is superior to the medium-scale dam scheme.

In addition, two further conclusions were derived from the above on the two conditions below:

Boundary Conditions

(i) The large-scale dam scheme is possible only on the condition that the people at Thaviang Sub-District agree to resettle to other places.

(ii) It may be possible to relieve all villages and cultivation lands from inundation if FSL is lowered to EL.310m or less.

*Note: As a result of the 3rd Field Investigation, it was confirmed that EL.310m is the maximum reservoir level, which relieves villages and cropping lands in Thaviang Sub-district from inundation and a part of Ban Pou and its farmland may be inundated at EL.320m. However in the near future, B.Pou will be relocated to the area along National Route-4, where will not be affected by inundation by a national plan irrespective to the Project.

Conclusions at 1st Comparative Study

(i) The large-scale dam scheme is economically optimum development.

(ii) The medium-scale dam scheme is the economic-viable and environment-optimum development. Its least impact FSL may be located at around EL.320m.

(3) 2nd Economic Comparison Result

The 2nd economic comparison was carried out for the alternative FSLs between EL.310m and EL.390m at 10m intervals. The methodology of analysis and the hydrological and topographic data are the same as those used in the 1st alternative study. However, the inundation area of paddy fields, the population for resettlement and the construction costs were reviewed referring to the latest data. The summary of the comparative economic aspects of the respective scale is as shown below:

Table 6.3.10 2nd Economic Comparison of Alternative Dam Type Schemes

No.	FSLs	Inst.Capacity (MW)	Total Energy (GWh)	Const. Cost (Mil. US$)	B/C	B-C (Mil. US$)	EIRR (%)
1.	EL.310m	214	1,192	316.3	1.55	129.83	16.39%
2.	EL.320m	240	1,349	339.6	1.64	163.21	17.52%
3.	EL.330m	263	1,508	367.5	1.68	186.44	17.85%
4.	EL.340m	280	1,626	392.1	1.69	202.60	17.97%
5.	EL.350m	314	1,777	420.4	1.73	230.85	18.52%
6.	EL.360m	334	1,905	445.6	1.76	252.46	18.81%
7.	EL.370m	356	2,030	476.1	1.75	265.83	18.65%
8.	EL.380m	377	2,148	505.0	1.75	282.37	18.69%
9.	EL.390m	401	2,282	538.4	1.74	299.29	18.65%

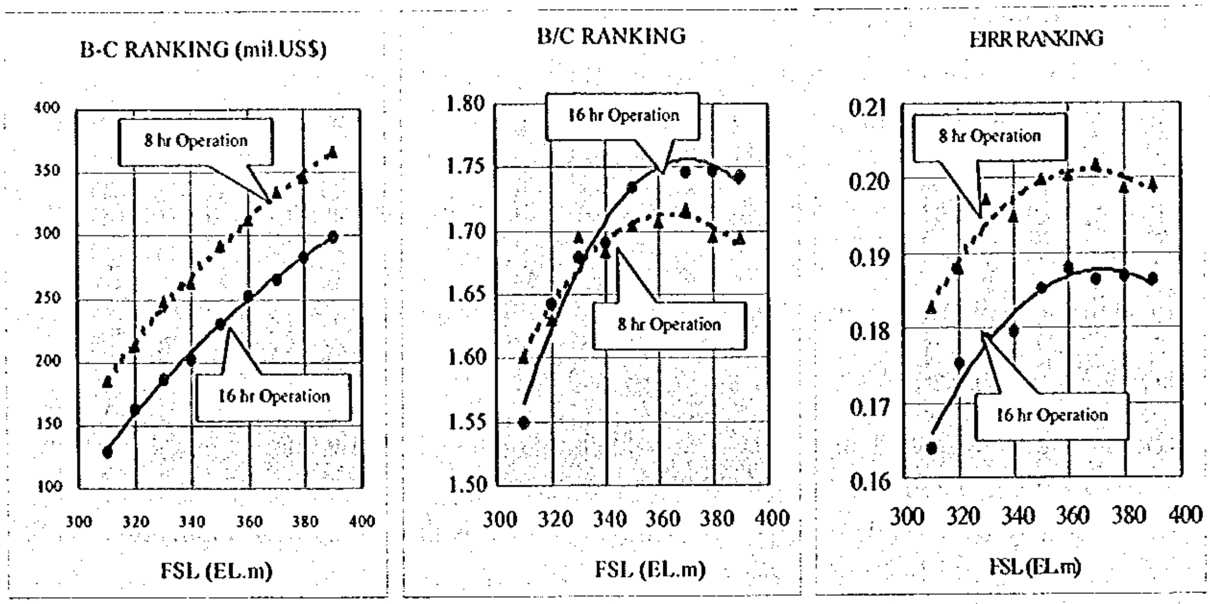


Figure 6.3.8 Results of 2nd Economic Comparison

From the above, it was clear that economic-optimum development scale is FSL.360m and environment-optimum scale is around FSL.320m. Therefore, the 3rd economic comparison study should be concentrated for these two (2) dam development scales to investigate the most recommendable financing method for each development scale.

Then, the final recommendable development scheme of the Project will be determined as the result of the overall assessment of the three (3) main parameters for judgement, namely (i) natural & social environmental issues, (ii) economic issues, and (iii) financial issues (financing plan).

(4) 3rd Economic Comparison Result

The results of 3rd economic comparison is shown in Table 6.3.11. The project features, the hydraulic characteristics and structural dimensions, construction work quantities, construction cost and environmental impact mitigation cost are shown in Tables 6.4.6 to 6.4.12.

Table 6.3.11 3rd Economic Comparison of Alternative Dam Type Schemes

No.	Particular	Unit	Medium-Scale FSL EL.310m	Large-Scale FSL EL.360m
1.	Installed capacity	MW	240	334
2.	Total energy production	GWh	1,349	1,905
3.	Project construction cost	Mil.US$	346.0	464.0
4.	B	Mil.US$	417.1	585.7
5.	C	Mil.US$	258.7	347.0
6.	B/C	-	1.61	1.69
7.	B-C	Mil.US$	158.4	238.7
8.	EIRR	%	17.2	18.0

6.3.4 RUN-OF-RIVER TYPE ALTERNATIVE AND DEVELOPMENT SCALE

Viability of run-of-river type scheme was also studied as a supplemental function to the medium and small-scale dam schemes.

Through the 1st and 2nd Field Investigations made from August to December 1998, the upstream rapid of the Nam Ngiep River and a rapid on the Nam Phouan River (right bank branch of the main stream, which is located at 24km upstream of the dam site) were selected for the site of run-of-river type alternatives. The run-of-river type alternatives have been named respectively as "Main Run-of-River Type Scheme" and "Branch Run-of-River Type Scheme", of which provisional configurations are as follows:

Table 6.3.12 Configuration of Run-of-River Type Alternatives

No.	Alternatives	Description	Q firm(*1)	Q max (*2)
1.	Main Run-of-River Type Scheme	By construction of a waterway of 8.6km long from the prospective intake site at 108km U/S of the dam site, about 273m of total head (EL.658m of intake sill to EL.385m of T.W.L) will be secured. The watershed at the intake site is 765 km^2.	$6.46m^3/s$	$26.38m^3/s$
2.	Branch Run-of-River Type Scheme	The practical maximum head will be about 80m (EL.425m of intake sill to EL.345m of T.W.L) by extension of a waterway of 2.5km long from the prospective intake site at 8km upstream of the confluence. The watershed at the intake site is $473km^2$.	$3.99m^3/s$	$16.30m^3/s$

Notes; (*1) 90% dependable run-off, (*2)at 70% of flow utilization factor.

Power intake of the Main Run-of-River Scheme planned on the main stream is located at 160km upstream from the confluence with the Mekong or 105km upstream of the main dam site where the riverbed is EL.658m on the 1:50,000 map. Power outlet of the scheme is located at 9km downstream of the intake site, of which the riverbed is EL.385m on the same map.

A branch, the Nam Phouan River, where a Branch Run-of-River Scheme was planned, will join with the Nam Ngiep River at 24km upstream of main dam site.

As the result of the study made during the 3rd Field Investigation carried out in February 1999, however, run-of-river type schemes were deleted from the development alternatives, because the relative basin inflow to the required waterway length (8,600m long for main run-of-river, 2,500m long for branch run-of-river) is quite small as shown below for both run-of-river schemes.

By the rough economic evaluation, it was revealed that power generation, which is appropriate to the cost for power waterway, is not expected by the run-of-river type scheme. In other words, electricity produced from the run-of-river scheme is quite expensive. Thus, these schemes are not feasible even by the development as a supplemental plant for the dam scheme. Results of a rough economic evaluation made for the run-of-river schemes are as follows:

Table 6.3.13 Economic Comparison of Alternative Run-of-River Type Schemes

No.	Items	Main Run-of-River Scheme	Branch Run-of-River Scheme
1.	Cost of waterway	= 5,000 US$/m x 8,600m = US$ 43 mil.	= 5,000 US$/m x 2,500m = US$ 12 mil.
2.	Produced Energy	= 9.8 Q H μ x 8,760 x 70% = 91.9×10^6 kWh	= 9.8 Q H μ x 8,760 x 70% = 18.4×10^6 kWh
3.	Unit waterway cost	= more than 0.47US$/kWh	= more than 0.65US$/kWh

Note: 70% in the above equation means annual plant factor.

6.4 CONSTRUCTION COST ESTIMATE & ECONOMIC EVALUATION OF NATURAL & SOCIAL ENVIRONMENTAL IMPACTS

6.4.1 CONDITIONS FOR PROJECT COST ESTIMATE

Usually the following items are to be included in the economic project costs:

(i) Construction cost (construction preparatory works cost, direct construction cost of civil and generating units, administration cost, engineering services cost, etc.),

(ii) Operation and maintenance (O&M) cost after construction (O&M costs for generating equipment, periodic repairing costs, costs for plant renewal, etc.), and

(iii) Environmental impact mitigation cost (resettlement cost, cost for relocation road, environmental impact mitigation cost).

However, item (i) does not include costs for land compensation, taxes, interests during construction, etc. And, item (iii) also does not include outfit allowance for resettlement, guarantee fund for villagers' living after movement at a decent-life level for several years, which were once consumed as project cost, but restored after all by the people (nation).

In due consideration below, the economic cost also does not include Shadow Prices (that are a part of the market prices, which was distorted by various factors such as political interference, excessive valuation of local currency, etc.):

(i) Domestic inputs were assumed to be negligible,

(ii) Skilled and semi-skilled workers were assumed in short supply locally, and

(iii) Share of the cost for unskilled workers is negligible small.

6.4.2 ESTIMATE OF CONSTRUCTION WORK QUANTITIES

Construction work quantities for each alternative scale are computed by a simplified method on the following basic structural conditions and criteria (Table 6.4.1).

Table 6.4.1 Construction Work Quantities

Main Dam Structure		Power Waterway	
Type of dam	Concrete faced rockfill dam	Type of headrace tunnel	Pressure type
Upstream slope	1 : 1.40	Type of penstock line	Pressure type, Steel lined conduit
Downstream slope	1 : 1.30	Type of tailrace	Open channel type
Freeboard above FSL	5.0 m	Max. limit of tunnel dia.	10 m
Dam crest width	10 m	Min. limit of tunnel dia.	3 m
Top soil stripping	5 m	Max. flow velocity of tunnel	Headrace tunnel:4.0m/s Penstock line :8.0m/s

The critical path of construction of the Project will be on the series of the work for river diversion, dam embankment, reservoir impoundment and wet testing for hydro-mechanical and electromechanical equipment. Construction period of each scheme was provisionally assumed to be five (5) years for all alternative schemes.

6.4.3 ESTIMATE OF CONSTRUCTION UNIT PRICES

Construction costs were preliminary estimated on the basis of international competitive bidding (ICB).

At the 1st Economic Evaluation, the unit prices of major civil work items were estimated multiplying 1.2 by the average value of the four comparative contract unit prices of the other similar hydropower projects, which are under construction or recently completed in Asian countries. In addition to the above four (4) projects, the contract prices for two (2) projects in Lao PDR were considered as an average for the 2nd Economic Evaluation. The adopted unit prices for both stages are as given on the right-end column in the table below:

Table 6.4.2 Contract Unit Prices of Major Civil Works at Various ICB-Base Projects (US$)

Project Name	Unit	(1)	(2)	(3)	(4)	(5)	(6)1st Stage (1)-(4)x1.2	(7)2nd Stage (1)-(5)
Open excavation, common	m^3	3.0	2.0	4.0	3.0	1.5	3.6	2.7
Open excavation, rock	m^3	8.0	4.0	11.0	6.0	4.0	8.7	6.8
Tunnel excavation	m^3	32	31	53	34	40	45	38.8
Dam embankment (rock)	m^3	7	9	8	6	2.1	9	6.3
Open structural concrete	m^3	125	62	114	99	90	120	92.9
Tunnel lining concrete	m^3	191	93	210	96	130	177	140.5
Reinforcement bar	t	1,050	608	1,048	619	1,000	998	797
Foundation grouting	m	126	110	141	128	100	152	114.1

Remarks; (i) Unit price of dam embankment shows the price for use of materials obtained from rock quarries,
(ii) Unit price of tunnel excavation includes costs for all kinds of tunnel support,
(iii) Unit price of concrete works includes costs for formwork, and
(iv) Project description for the above are as shown below:

No.	Project Name	Country	Type of Dam	Dam Height	Status
(1)	Karun-4	Iran	Rockfill	180m	under const.
(2)	Way Sekampung	Indonesia	Rockfill	113m	under const.
(3)	Samanarawewa	Sri Lanka	Rockfill	100m	completion in '94
(4)	Da Mi*	Vietnam	Rockfill	70m	under const.
(5)	Theun Hinboune	Lao PDR	Concrete weir	-	completion in '98
(6/7)	Nam Ngiep-I	Lao PDR	Rockfill	185m	under planning

In addition, the unit prices for electrical/mechanical works of the Project were estimated referring to the similar international hydropower projects, which were recently constructed by ICB contract.

6.4.4 COST ESTIMATE OTHER THAN DIRECT CONSTRUCTION COST

(1) Conditions for Cost Estimate of Operation and Maintenance (O&M)

Economic life and frequency for replacement of generating equipment were assumed to be 50 years and 30 years, respectively. And, the discount rate is applied at 10%.

Annual O&M cost of hydropower plants was assumed to be the fixed rate of 1.0% of the total capital cost. Power losses of hydropower plant were assumed as follows:

Table 6.4.3 Assumed Power Losses of Hydropower Plant

Item	kW	kWh
Power loss through transmission line	4.0 %	5.0 %
Forced operation outage	2.5 %	2.5 %
Maintenance outage	1.0 %	1.0 %
Consumption at power station	1.1 %	0.7 %

(2) Estimate of Environmental Impact Mitigation Costs

Not only limited to hydropower development, but also at all kinds of rural development, the recent trend is going to directly evaluating the natural and social environmental impacts in the economic analysis for the project. In line with the above trend, the Nam Ngiep-1 HEPP has also taken widely and positively into account natural-social environmental impacts and quantitatively evaluated and converted those into monetary values.

In other words, positive or negative values derived from the natural-social environmental impacts are not considered as financial values to be evaluated for private or business merit. It should be evaluated as a social opportunity cost and benefit (economic cost) from the viewpoint of national social welfare.

A large dam scheme development will be accompanied with an extensive involuntary resettlement by inundation and a decline of CO_2 purification effect in the river basin due to vanishing forest (negative indirect factors to the Project benefit). On the other hand, the Project will produce various positive indirect benefits, such as construction of new roads for access to the construction sites, flood regulation by reservoir, possible pump irrigation and rural electrification for the downstream area, fishery/ferry service/tourism in the reservoir, provision of job opportunity and regional economic activation due to the above benefits, so on.

Most of the environmental negative factors are indemnified with the collateral project measures such as preservation, compensation, countermeasure, etc. The natural-social environmental impacts, which can be quantitatively evaluated, are shown in Table 6.4.4 together with its collateral solution, and the monetary conversion for these solutions are shown at the end of Chapter 6.4.

Table 6.4.4 Collateral Solutions for Quantitatively Evaluated Impacts

No.	Natural-Social Environmental Impacts	Collateral Solution
1.	Inundation of villages	Supply of equal-scaled resettlement facilities
2.	Peoples' mental burden for resettlement (*1)	Monetary support such as outfit allowance for resettlement and guarantee fund for villager's living after movement at a decent-life level for several years.
3.	Water level fluctuation at downstream due to discharge from power station	Provision of re-regulation pond for stabilization of water level
4.	Decreasing fishes at downstream reach	Promotion and construction of facilities for fishery
5.	River shore erosion at downstream reach	River protective works
6.	Tentative water pollution by hydrogen sulfide from the submerged forest	Provision of public wells for downstream villages
7.	Destruction (damage) of peoples' production due to construction	Compensation and relocation
8.	Sedimentation at upstream end of reservoir (*2)	Heightening river bank when actually required

(*1)	As the result of EIA, it was revealed that the present infrastructures in the Project area are not satisfactory to the villagers and local market is very stagnant. Judging from the above, even if the scale of resettlement becomes large, the consensus of the people will be positive towards the resettlement, if a meticulous welfare is provided to them with well-supply of local electrification, medical facilities, schools, public wells, etc., supply of equal-sized farmland, technical guidance for agriculture and stockbreeding, provision of industrial promotion center in the resettlement land, etc.
(*2)	Judging from the state of sedimentation measured for the existing Nam Ngum-1 reservoir, prospective sedimentation at the upstream end of the Nam Ngiep-1 HEPP reservoir is deemed to be negligibly small.

6.4.5 ECONOMICAL EVALUATION OF NATURAL AND SOCIAL ENVIRONMENTAL IMPACTS

(1) Interpretation for Other Natural-Social Environmental Impacts

For the impacts out of those listed in Table 6.4.4, the following interpretations are given:

(i) Mental-burden of the highland people in the form of changing living circumstances due to resettlement is considered to be set off by the contribution to the nation with the decreasing shifting cultivation and guarantee of their lives with well-supplied resettlement facilities and support.

(ii) Declined CO_2 purification effect in the river basin due to vanishing forest is considered to set off by the amount of CO_2 emission, which is expected to decrease by hydropower development instead of thermal plant construction.

(iii) Noise, dust, water pollution, etc. during construction will be restricted and minimized by applying careful construction control in conformity with the local environmental rules and regulations in Lao PDR.

(iv) In the tropical country, influence of the discharge for power generation, which will negatively affect adequate water temperature for irrigation, will be negligibly small.

(2) Indirect Benefits (Positive & Negative) difficult to Quantitatively Evaluation

Preparation of the impartial criteria for quantitative evaluations is quite difficult against the negative impacts on aquatic bio-diversity due to basin inundation and for the species, which migrate seasonally to and from the Mekong River, as well as the Project specific benefits other than earnings from export of electricity as shown in Table 6.4.5.

Based on the results of EIA for the respective items, and with reference to the actual environmental impact evaluations made for the other projects, quantitative and qualitative evaluation criteria for the environmental assessment of the Project will be established. Environmental impacts will be evaluated from a macroscopic viewpoint showing objectively the positive and negative impacts according to the established criteria.

Table 6.4.5 Interpretation for Specific Project Benefits (Positive & Negative) out of Income from Electricity

No.	New Economic Opportunities	Economic Effect
1.	Creation of reservoir	Flood regulation effect to downstream reach by reservoir storage function and prospective enlargement of irrigable area around reservoir
2.	Navigation in reservoir	Economical interconnection of Xieng Khouang Province and Bolikhamxay Province (*1) and prospective tourism development (*2)
3.	Fishery in reservoir (*3)	Stabilization of catch of fish and prospective development of rural socio-economy
4.	Increasing job opportunity by Project	Increasing people's living standard with more labor income
5.	Resettlement of highland people	Decreasing the area of shifting cultivation
6.	Technical guidance for agriculture and stockbreeding (*3)	Modernization of rural agriculture and stockbreeding
7.	Rural electrification by power supply from Project	Notable improvement in living circumstances and prospective rural industrial development
8.	Macro economic impact derived from Project	Decreasing poverty and regional economic activation
(*1)	Economic interconnection of both provinces, Xieng Khouang and Bolikhamxay will give impacts to the economic activities in the remote Xieng Khouang Province, which were not briskly due to poor transportation conditions and security problems of National Road Nos. 4 and 7.	
(*2)	Assuming from the trend of national economic expansion to the Southern region, as well as the recent inroads of tourism into the areas near the existing Nam Ngum-1 reservoir, it is also presumed that development of tourism will be expected for the areas around the Nam Ngiep-1 reservoir soon after the completion of the Project. Especially the Thaviang Sub-District, from its topographic advantage with widely developed flat land along the reservoir, has a high possibility of tourism development as a resort area.	
(*3)	By the construction of a rural industrial promotion center in the main resettlement area, technical guidance will be provided to the resettlement people dispatching several foreign experts for the respective sector. For the above plan, the annual cost required for a practical three years service period was appropriated in Table 3.4.15-D as the cost for industrial promotion guidance.	

Table 6.4.6 Project Features for Alternative FSLs

Particular	Unit	Alternative FSL (EL.M)	
		FSL.320m	FSL.360m
Annual average rainfall	mm	2,470	2,470
Catchment area	km²	3,700	3,700
Run-off coefficient	-	0.56	0.56
Annual basin inflow	mill. m³	5,118	5,118
Specific run-off	m³/km²	1.4	1.4
Annual mean runoff	m³/sec	162.3	162.3
River bed at damsite	EL. m	173	173
Ultimate sediment level	EL. m	200	200
Dead water depth, dwd	m	80	135
Head variation ratio =abt.0.7	-	0.72	0.86
Min. oper. level, MOL	EL. m	280	335
Drawdown	m	40	25
Drawdown ratio, d / Hg	%	30	14
Rated pond level	EL. m	307	352
Pond area at FSL	km²	73.9	148.2
Pond area at MOL	km²	23.1	113.0
Gross storage capacity, Vg	mil. m³	2,279	6,782
Net storage capacity, Ve	mil. m³	1,779	3,092
Regulation ratio, Ve / R	%	35	60
Maintenance flow	m³/sec	0	0
Peak output duration	hrs	16.0	16.0
Rated tail water level	EL. m	174.8	174.8
Min. tailwater level (Riverbed)	EL. m	173	173
Gross head, Hg	m	131.8	176.8
Power waterway length	m	600	700
Loss head	m	3.13	3.78
Rated head, Hd	m	131.8	176.8
Ave. combined unit efficiency	m	0.888	0.888
Max. discharge, Qp	m³/sec	221.0	224.0
Supply ratio, Qp/Ia	%	136	138
Supply durability, Ve/Qp	day	93	160
Peak output	MW	240	334
Mean annual energy	GWh	1,349	1,905
Annual plant factor	%	64.2	65.1
Number of unit	no.	2	3
Unit turbine capacity	MW	120	120
Specific speed, Ns	m-kW	140	120
Rated speed, N	rpm	180	230
Unit rated output, P	MVA	146	135

Economic cost and vaiability at different FSLs Unit : million US$

Particular	Unit	Alternative FSL (EL.M)	
		EL.320m	EL.360m
Construction cost	mill.US$	291.2	376.4
Env. impact mitigation cost	mill.US$	17.5	28.7
Engineering service cost	5%	15.4	20.3
Administration cost	5%	15.4	20.3
Contingency	0%	0.0	0.0
Project cost	mill.US$	339.6	445.6
Specific capacity cost	US$/kW	1,415	1,334
Constuction period	year	5	5
Annual cost	mil.US$	253.9	333.2
Annual benefit	mil.US$	417.1	585.7
B - C	mil.US$	163.2	252.5
B / C	-	1.64	1.76
EIRR	%	17.5%	18.8%
Economic life time (year)	Year	50	50
Discount rate	-	10%	10%

Table 6.4.7 Hydraulic Characteristics and Structural Dimensions at FSL.360m and FSL.320m

Particular	Unit	Alternative FSL (EL.m)	
		FSL.320m	FSL.360m
1. River Diversion Scheme			
Tunnel discharge	m^3/sec	2,903	3,245
Number of diversion tunnel	no.	2	2
Tunnel diameter	m	9.6	10.2
Tunnel length	m	1,100	1,200
Tunnel lining thickness	m	0.5	0.5
2. Dam			
Main dam crest level	EL. m	325	367
Crest length	m	524	662
River bed	EL. m	167	167
River width	m	60	60
Main dam height	m	157	197
Main dam u/s slope	-	1.40	1.40
Main dam d/s slope	-	1.30	1.30
Saddledam height	m	0	0
Saddledam crest length	m	0	0
3. Spillway			
Specific runoff	$m^3/s/km^2$	5.0	5.0
Design discharge	m^3/s	15,900	15,900
4. Bottom Outlet			
Design discharge	m^3/s	425	425
Number of tunnel	no.	1	1
Diameter of tunnel	m	7.4	7.4
Tunnel length	m	800	850
Tunnel lining thickness	m	0.5	0.5
5. Power Waterway			
Maximum plant discharge	m^3/sec	221	224
Effective head	m	132	177
Headrace tunnel length	m	420	490
Number of headrace tunnel	no.	2	2
Unit tunnel discharge	m^3/sec	111	112
Radius of headrace tunnel	m	3.4	3.4
Tunnel lining thickness	m	0.4	0.4
Number of penstock	no.	2	3
Average diameter of penstock	m	2.5	1.9
Penstock length	m	180	210
Penstock weight /m/no.	ton	1.1	0.8
6. Powerhouse			
P/H excavation / unit	$10^3\ m^3$	14	19
P/H concrete / unit	$10^3\ m^3$	9	12
7. T/L & S/S			
Transmission line voltage	KV	230	230

Table 6.4.8 Construction Work Quantities at FSL.360m and FSL.320m

Particular	Unit	Alternative FSL (EL.m)	
		EL.320m	EL.360m
1. River Diversion Scheme			
Open excavation	10^3 m^3	71	78
Tunnel excavation	10^3 m^3	195	235
Tunnel lining concrete	10^3 m^3	34.9	40.2
Curtain grouting	10^3 m	6.3	8.4
Consolidation grouting	10^3 m	8.3	10.5
Re-bar	ton	1,398	1,608
Cofferdam embankment	10^3 m^3	290	320
2. Dam			
Main dam embankment	10^3 m^3	6,896	12,744
Foundation excavation	10^3 m^3	658	1,043
Curtain grouting	10^3 m	35.7	56.3
Consolidation grouting	10^3 m	13.6	17.1
Open concrete works	10^3 m^3	46.8	63.4
Re-bar	ton	2,339	3,172
Saddle dam embankment	10^3 m^3	0	0
3. Spillway			
Open excavation	10^3 m^3	4,949	5,190
Open concrete works	10^3 m^3	361	452
Re-bar	ton	10,818	13,574
4. Bottom Outlet			
Open excavation	10^3 m^3	22	22
Tunnel excavation	10^3 m^3	44	47
Tunnel lining concrete	10^3 m^3	9.9	10.5
Curtain grouting	10^3 m	2.2	2.8
Consolidation grouting	10^3 m	1.5	1.9
Re-bar	ton	395	420
5. Intake			
Open excavation	10^3 m^3	79	96
Open concrete works	10^3 m^3	28	34
Re-bar	ton	844	1,012
6. Headrace Tunnel			
Tunnel excavation	10^3 m^3	39	46
Tunnel lining concrete	10^3 m^3	8	10
Re-bar	ton	335	393
Consolidation grouting	10^3 m^3	9	11
7. Penstock Line			
Open excavation	10^3 m^3	10	7
Open concrete works	10^3 m^3	2.2	2.0
Re-bar	ton	43.1	40.7
8. Powerhouse			
Open excavation	10^3 m^3	28	56
Open concrete works	10^3 m^3	18	37
Re-bar	ton	885	1,842
9. Metal Works			
Diversion tunnel stoplogs	ton	435	487
Spillway stoplogs	ton	477	477
Sillway gates	ton	3,180	3,180
Bottom outlet valves	ton	213	213
Intake screen and gate	ton	535	560
Penstock steel	ton	387	520
Tailrace gates	ton	141	142
10. Generating Equipment			
Water turbine	ton	1,300	1,727
Generator	ton	2,241	2,706
Transforner	MVA	291	405
11. Transmission Line and Substation			
Transmission line length	km	110	110

Table 6.4.9 Construction Cost at FSL.360m and FSL.320m (1/2)

A. Direct Construction Cost (1,000US$)

Particular	Unit	Unit Price (US$)	Alternative FSL (EL.M) 320	360
(1) River Diversion Scheme			17,103	20,248
Open excavation	m³	5.6	394	436
Tunnel excavation	m³	38.8	7,551	9,114
Lining concrete	m³	140.5	4,910	5,648
Curtain grouting	m	114.1	721	957
Consolidation grouting	m	114.1	951	1,200
Re-bar	ton	797.0	1,114	1,282
Cofferdam embankment	m³	5.0	1,462	1,613
(2) Dam			58,955	102,900
Main dam embankment	m³	6.3	43,417	80,286
Foundation excavation	m³	5.6	3,666	5,811
Curtain grouting	m	114.1	4,074	6,424
Consolidation grouting	m	114.1	1,557	1,957
Open concrete works	m³	92.9	4,347	5,894
Re-bar	ton	797.0	1,864.5	2,528.3
Saddle dam embankment	m³	5.7	0	0
(3) Spillway			69,685	81,763
Open excavation	m³	5.6	27,565	28,911
Open concrete works	m³	92.9	33,499	42,034
Re-bar	ton	797.0	8,622	10,818
(4) Bottom Outlet			3,951	4,272
Open excavation	m³	5.6	122	122
Tunnel excavation	m³	38.8	1,702	1,809
Lining concrete	m³	140.5	1,387	1,474
Curtain grouting	m	114.1	251	315
Consolidation grouting	m	114.1	174	219
Re-bar	ton	797.0	315	334
(5) Intake			3,729	4,474
Open excavation	m³	5.6	441	532
Open concrete works	m³	92.9	2,615	3,135
Re-bar	ton	797.0	673	807
(6) Headrace Tunnel			4,015	4,724
Tunnel excavation	m³	38.8	1,497	1,768
Lining concrete	m³	140.5	1,176	1,381
Re-bar	ton	797.0	267	313
Consolidation grouting	m	114.1	1,075	1,261
(7) Penstock Line			292	258
Open excavataion	m³	5.6	58	36
Open concrete works	m³	92.9	200	189
Re-bar	ton	797.0	34	32
(8) Powerhouse			2,505	5,204
Open excavation	m³	5.6	155	314
Open concrete works	m³	92.9	1,644	3,422
Re-bar	ton	797.0	705	1,468
(9) Miscellaneous Civil Works				
Civil Works (No.1 to No.8)	-	1.0%	1,602	2,238
(10) Metal Works			33,172	34,198
Diversion tunnel stoplogs	ton	4,000	1,742	1,947
Spillway stoplogs	ton	4,000	1,908	1,908
Spillway gate	ton	7,000	22,260	22,260
Bottom outlet valves	ton	6,000	1,275	1,275
Intake screen and gate	ton	6,000	3,211	3,358
Penstock pipe	ton	5,000	1,933	2,598
Tailrace gates	ton	6,000	843	852
(11) Generating Equipment			62,759	80,814
Water turbine	ton	14,000	18,206	24,175
Generator	ton	13,000	29,130	35,175
Transformer	MVA	8,000	2,328	3,240
Indoor switchgear	MVA	30,000	8,730	12,149
Ancillary equip. and others	MVA	15,000	4,365	6,075
(12) Transmission Line and Substation			23,292	24,660
Transmission line	km	180,000	19,800	19,800
Substation	MVA	12,000	3,492	4,860
(13) Miscellaneous M & E Works				
M & E Works (No.10 to No.12)	-	1.0%	1,192	1,397

Table 6.4.10 Construction Cost at FSL.360m and FSL.320m (2/2)

B. Preparatory Works Cost (1,000US$)

B-1 Construction of Temporary Facilities

Alternative FSL (EL.M)

Particular		Unit	320	360
New road construction		km	10.0	10.0
Existing road betterment		km	33.0	33.0
Telecommunication line		km	35.0	35.0
Power distribution line		km	35.0	35.0
Employer's site facilities		m^2	10,000	10,000
New road construction	300,000	US$/km	3,000	3,000
Road betterment	100,000	US$/km	3,300	3,300
Telecommunication	10,000	US$/km	350	350
22kV power distribution	20,000	US$/km	700	700
Employer's facilities	10	US$/$m^2$	100	100
Total cost		(1,000US$)	7,450	7,450

B-2 Other Compensation

Particular		Unit	320	360
Access road (W=30m)		m^2	300,000	300,000
Dam site		m^2	152,200	236,600
Power station		m^2	8,400	10,500
Others		m^2	138,200	164,200
Total area to be compensated		m^2	598,800	711,300
Total cost (1,000US$)	2.5	US$/$m^2$	1,497	1,778

B-3 Relocation of Road at Thaviang District

Particular	Unit	320	330
Relocation road (=FSL Area / 5km2)	km	15	15
Total cost	(1,000US$)	2,250	2,250
Unit const. construction (US$/km)	150,000		

C. Environmental Impact Mitigation (EIM) Cost

C-1 Constrution of Environmental Appurtenant Structures

Particular	Unit	320	360
Re-regulation facility	(1,000US$)	3,315	3,360
Berthing facility in reservoir	(1,000US$)	162	226
River protection work	(1,000US$)	2,210	2,240
Total cost	(1,000US$)	5,687	5,826

C-2 Environmental Monitoring & Planning (For detail, See Chapter 7, Table 7.5.1-2)

Particular	Unit	320	360
Total cost	(1,000US$)	7,664	10,678

D. Resettlement Cost (For detail, See Chapter 7, Table 7.6.3-4)

Particular	Unit	320	360
Preparation of Resettle. Plan (Table 7.6.3)	(1,000US$)	600	1,100
Execution of Resettlement (Table 7.6.4)	(1,000US$)	7,114	23,334
Total cost	(1,000US$)	7,714	24,434

E. Total Project Cost

Particular	Unit	320	360
Direct Construction Cost of Civil (1-9)	(1,000US$)	161,838	226,083
Direct Construction Cost of M&E (10-13)	(1,000US$)	120,415	141,068
Preparatory Works Cost (B-1 to B-3)	(1,000US$)	11,197	13,728
Total Construction Cost (I)	(1,000US$)	293,450	380,879
EIM Cost (C-1 to C-2)	(1,000US$)	13,351	16,504
Resettlement Cost (D)	(1,000US$)	7,714	24,434
Total Environmental Cost (II)	(1,000US$)	21,065	40,938
Total Project Cost (III = I + II)	(1,000US$)	314,515	421,817

F. Ration of EIM Cost to Total Project Cost

Particular	Unit	320	360
Ratio of EIM Cost (= II / III)	(%)	6.7%	9.7%

Note: Environmental Impact Mitigation (EMI) costs in the above table are used for 3rd economic and financial evaluations only.

Table 6.4.11 Construction Cost and Annual Costs of Alternative Thermal Plant

	Hydropower		Thermal Unit	
	kW	kWh	kW	kWh
Transmission loss rate	4.0%	5.0%	1.5%	1.2%
Forced operation outage	0.5%	0.5%	5.0%	2.5%
Maintenance outage	0.4%	0.4%	13.0%	22.0%
Station use rate	1.1%	0.7%	2.7%	1.0%
		Adjusting factors:	1.188	0.964

	Hydropower	Gas Turbine	C. Cycle
Annual O&M cost rate	1.0%	2.5%	2.5%
Kind of fuel	-	fuel oil	natural gas
Annual fuel cost rate, cent/kWh	-	7.52	3.50
Unit capital cost of thermal unit, US$/kW	-	250	500
Plant capacity rate	-	20%	80%
Economic life time (year)	50	20	25

	Raw Price	End Price	Calorific Value		Efficiency	US$/kWh
High speed diesel, US$/ton	290	435	11,000	Kcal/kg	30%	0.113
Medium fuel oil, US$/ton	180	270	10,300	Kcal/kg	30%	0.075
Heavy oil, US$/ton	150	225	9,800	Kcal/kg	27%	0.073
Coal, US$/ton	30	45	5,300	Kcal/kg	35%	0.021
Natural gas, US$/mil.btu	3.0	4.5	246,000	Kcal/mil.btu	45%	0.035
Geothermal, US$/kWh	0.04	0.06				0.060
Energy equivalent, Kcal/kWh	861					
1 kWh =	3,500	btu				
1 mil.btu =	286	kWh				

Particular	Unit	Alternative FSL (EL.M)	
		320	360
Thermal plant capacity	MW	290	400
Plant capacity of gas turbine	MW	58	80
Plant capacity of comb. cycle	MW	232	320
Thermal plant annual energy	GWh	1,301	1,837
Capital cost of gas turbine	106 US$	15	20
Capital cost of comb. cycle	106 US$	116	160
O/M cost of gas turbibe	106 US$	0.4	0.5
O/M cost of comb. cycle	106 US$	2.9	4.0
Fuel cost, gas turbine	106 US$	19.6	27.6
Fuel cost, comb. cycle	106 US$	36.4	51.4
Construction period, gas turbine	year	2	2
Construction period, comb. cycle	year	3	3

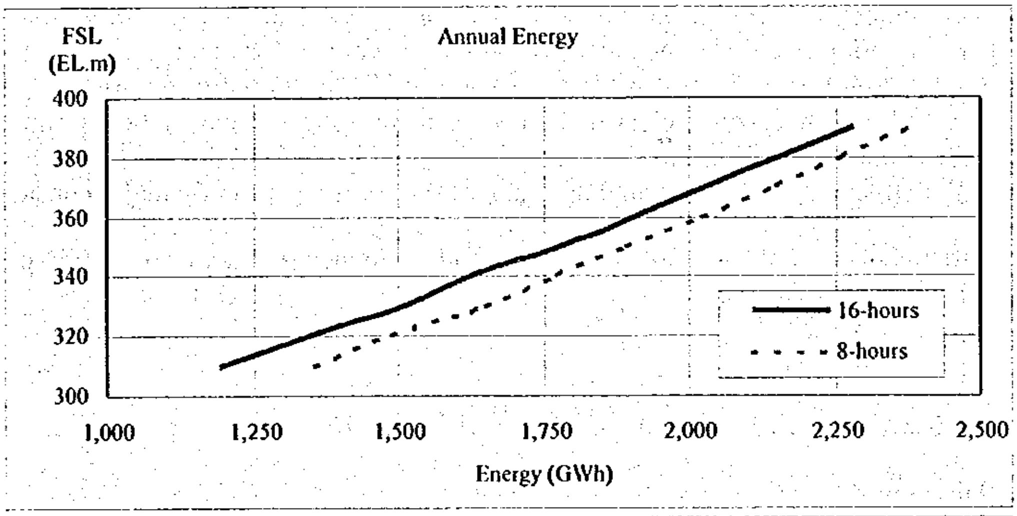
Table 6.4.12 Hydropower Potential at Different FSLs

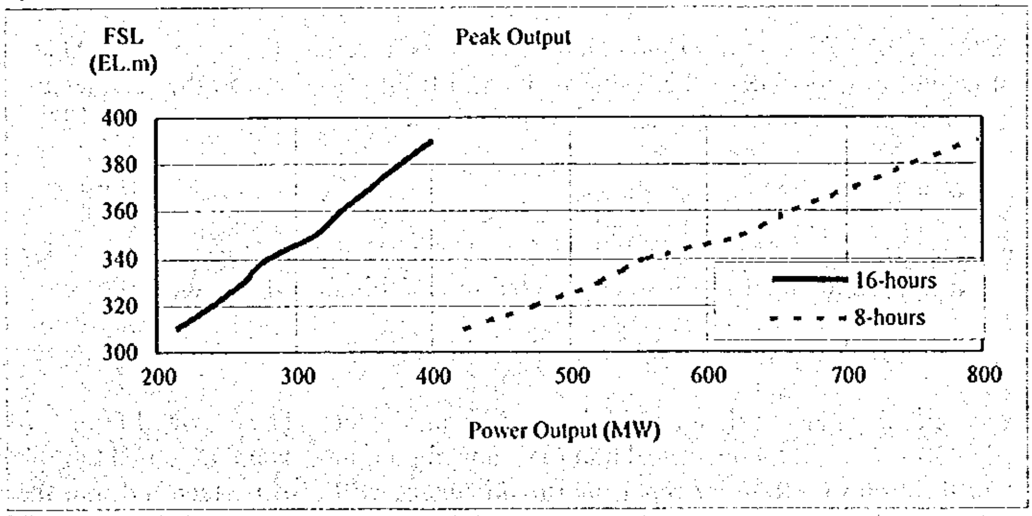
Operation: 16 hours

FSL	MOL	Q peak	Q ave	P max	E firm	E 2nd	E total	95% Energy
310	270	210.0	131.4	214	1,085	107	1,192	903
320	280	221.0	137.5	240	1,249	100	1,349	1,043
330	305	213.0	139.0	263	1,405	103	1,508	1,183
340	315	213.0	140.0	280	1,518	108	1,626	1,269
350	320	227.0	144.2	314	1,677	101	1,777	1,382
360	335	224.0	145.1	334	1,800	105	1,905	1,467
370	345	227.0	145.9	356	1,932	98	2,030	1,549
380	350	234.0	147.6	377	2,064	85	2,148	1,673
390	350	245.0	162.3	401	2,205	76	2,282	1,779

Operation: 8 hours

FSL	MOL	Q peak	Q ave	P max	E firm	E 2nd	E total	95% Energy
310	270	421.0	149.0	425	1,078	278	1,356	878
320	280	443.0	151.8	476	1,240	248	1,489	1,005
330	305	426.0	152.1	523	1,400	251	1,651	1,158
340	315	427.0	152.9	558	1,510	264	1,774	1,245
350	320	454.0	154.1	625	1,668	227	1,895	1,373
360	335	448.0	154.7	663	1,789	236	2,024	1,470
370	345	454.0	154.9	708	1,923	227	2,150	1,650
380	350	468.0	155.7	750	2,053	209	2,262	1,670
390	350	490.0	157.3	796	2,194	189	2,383	1,769





6.5 ECONOMIC AND FINANCIAL EVALUATION CRITERIA

6.5.1 APPROACH TO PROJECT ECONOMIC AND FINANCIAL EVALUATION

This chapter focuses on the economic and financial viability of the Project. The economic analysis compared project cost to the cost that would have been incurred should thermal units be used, thus deriving the benefits of avoided cost. Avoided cost, in this case, could be used as a proxy to Least Cost Analysis, assuming that any project which is cheaper than the combination of gas turbine and combined cycle is fit into the Least Cost Expansion Plan.

As the current trend dictates and the GOL's policy encourages private sector participation in hydropower generation, financial analysis of the Project is becoming more and more important. Even if the GOL/EDL is going to undertake this Project by themselves, an independent commercial operation entity may be established to be responsible for its own profits and losses.

From the Study Team's perspective, the critical question that the financial analysis should answer is whether the overall project is profitable, and whether the potential investors, private or public, or joint efforts, will see the incentives attractive enough for them to forgo the investment opportunities elsewhere to invest in the Nam Ngiep-I HEPP. Equally important is whether the Project could bring a reasonable level of income to the government, national and provincial, through dividends distribution, taxes, royalty, and other charges and duties while maintaining an affordable tariff level, no higher than that of one of the six IPPs currently under consideration.

A detailed financial analysis was carried out and a financing scheme of public-private joint investment (BOT) was tested.

6.5.2 PARAMETERS FOR PROJECT EVALUATION

(1) Discount Rate

A discount rate of 10% was used in economic analysis to reflect the opportunity cost or scarcity value of capital in Lao PDR. This value is derived from referring to other studies in Lao PDR. A discount rate of 12% was also tested. For financial analysis, a discount rate of 12% was used.

(2) Exchange Rate

An exchange rate of US$1.00 for 9,000 kips and 37.0 Thai Bahts was used as reference only. However, the cost and benefits are all considered in US dollars at this stage.

(3) Project Life

The project life depends on the endurability of its components. The service life of civil works is assumed at 50 years and the electrical and mechanical components are assumed to replace during the life of the Project. Regular repair and maintenance will also be factored into the recurrent cost. However, for financial analysis, only the concession period, 25 years in this case, is considered.

(4) Others

The cost estimates and corresponding cash flows in economic analyses reflect the mid-1999 price level. International inflation is assumed to be 2.4% per year, based on the World Bank's Manufactures Unit Value (MUV) projection up to the year 2010.

6.5.3 VALUATION OF COST

(1) Cost for Project Evaluation

The cost estimated is based on the detailed figures presented in Chapter 6.4. The construction period is assumed to start from the year 2006, and last to the year 2010. The Commercial Operation Date (COD) is assumed in the year 2011. Any cost, such as engineering and preparation fees, before the year 2006 is treated as the cost incurred in the year 2006.

(2) O&M and Replacement Costs

Annual operation and maintenance costs for the hydropower plant are estimated on the basis of the general experience of the consultants for plants under similar conditions, and on specific information for other hydropower plant in the region. The average rate for O&M is assumed at 1.0% per annum of the base cost. In financial analysis, however, the O&M rate is assumed to escalate by the rate of 2.5% per annum.

The replacement of various equipment at intervals during the project lifetime has been included in the economic analysis with a common operation rule, a lump-sum replacement cost, is input in the 31st and 32nd year of operation.

6.5.4 VALUATION OF BENEFITS

(1) Power Benefits

The output of the Nam Ngiep-I HEPP is assumed to be at the connection point of the 500kV level. A capacity contribution designated by the capacity available for 16-hr/day and 6-day/ week throughout the year.

The economic benefits in first year of operation is assumed using avoided thermal cost. The financial benefits in the first year is calculated using a tariff schedule that will be described in Chapter 6.7.4.

(2) Indirect or Secondary Benefits

Indirect or the secondary benefits would include the creation of employment opportunity and improved living standards of the people around the Project site. This in turn will have ripple effects on socio-economic development of the region. Construction of dam would mitigate flood hazards thus reducing damage to local infrastructure, livestocks and time waste on economic activities, in addition to agriculture benefits. The export of energy will earn foreign exchanges, which are badly needed for import of manufactured goods. These benefits are difficult to quantify at this stage and therefore not considered in the economic and financial analysis. However, they should not be ignored while making decisions for the selection of the Project.

(3) Environmental Benefits

Environmental benefits of avoiding thermals units in Thailand are substantial. Although they were not considered in the FSL.320m Alternative, they will be tested at the next stage of Feasibility Study, using the internalized environmental cost of thermal units. Based on a World Bank study, "Incorporating Environmental Concerns into Power Sector Decision-making, 1994", the environmental cost for coal fired generation is about USc1.73/kWh, gas turbine about USc1.45/kWh, and combined cycle USc0.94/kWh.

6.6 ECONOMIC EVALUATION

6.6.1 GENERAL

To find out the optimum development scheme of the Project, the alternatives have been evaluated from the standpoint of national income gauging essential benefits and costs in the usual Discounted Cash Flow Method as shown below:

(i) Calculate the costs of the Project and prepare an annual investment schedule for the project total period (construction period plus project life time),

(ii) Calculate the benefits of the Project and prepare an annual investment schedule (hydropower potential was calculated for the respective FSL on a tentative reservoir operation rule and based on the existing topography and basin hydrology),

(iii) Convert the figures in the cost stream and benefit stream to their present values,

(iv) With the cost and benefit streams expressed in their present values, calculate the economic indices (net present values of B-C, B/C, and EIRR), and

(v) Evaluate economic viability of the Project based on the computed economic indices from the requirements: B-C>0, B/C>1.0, EIRR>10%.

At the 1st economic analysis, three (3) alternative schemes with the large-scale (FSL.360m), the medium-scale (FSL.320m) and the small-scale (FSL.240m) dams were considered. And at the 2nd analysis, the alternatives between EL.310m and EL.390m with 10m intervals of both the large-scale and the medium-scale (FSL.320m) were evaluated in Chapter 6.3.3. Financial justification to be evaluated from the project administration's point of view were analyzed as the 3rd stage of economic comparison study in Chapter 6.7 based on the possible financing plan and assumed electricity export agreement.

6.6.2 PARAMETERS FOR ECONOMIC ANALYSIS

The basic assumptions for 2nd stage economic analyses are summarized as follows:

Table 6.6.1 Parameters for Economic Analysis

No.	Parameters	Unit	Economic Parameters	
			FSL.320m	FSL.360m
1.	Total Capacity (FSL.320m Alternative)	MW	240	334
2.	Plant Utilization Factor	%	64.2	65.1
3.	Total Cost (exclude IDC)	Mil. US$	339.6	445.6
4.	Years of the Project Considered	Years	50	50
5.	SCF	-	Not used	Not used
6.	O&M	%	1.0	1.0
7.	Auxiliary use and Line Loss	%	1.3	1.3

6.6.3 ECONOMIC ANALYSIS USING AVOIDED COST

In the economic analysis usually hydropower unit is replaced with alternative thermal power unit(s), which can generate equal electricity on an assumption that the implementation of alternative project will be planned when the hydropower project has been cancelled. For evaluation of the economic feasibility of the Project, the cost-benefit analysis was carried out after establishing an avoid cost of thermal power in Thailand.

The above concept of economic analysis is on the basis of the understanding that EGAT has policy of purchasing generated power from not only IPPs in Thailand but also other surrounding countries, and that the most competitive rivals are IPPs of the Thai thermal power. The analysis will prove that the hydro IPPs in Lao PDR shall be superior to the thermal IPPs in Thailand from the view point of national economy.

The energy generated from the Nam Ngiep HEPP is assumed to be delivered to the 500kV line at the border with a 1.3% auxiliary and line loss rate. Thermal plants contemplated in the recent Power Development Program (up to 2011) include 4x700MW Ratchaburi Thermal units of gas/oil fired units and 6x200 MW combined cycle units for base power supply.

Gas turbine and combined cycle were selected as alternative thermal units and its share was assumed to be 20% by gas turbine and 80% by combined cycle, which are similar to the ratio given for the national power development classification established by EGAT. Unit capital cost for the thermal plant was assumed to be US$250/kW for gas turbine unit and US$500/kW for combined cycle unit. Medium fuel oil was applied for gas turbine and natural gas was used for combined cycle. Price of medium fuel oil was assumed to be 180US$/ton and price of natural gas was assumed to be 4.0US$/mil.BTU for the estimation of annual fuel cost of thermal units. Unit fuel costs per kWh were computed by using the calorific values of 10,300 Kcal/kg and 30% thermal efficiency for medium fuel oil and 246,000 Kcal/mil.BTU and 45% thermal efficiency for natural gas.

Annual O&M cost for thermal units was assumed to be the fixed rate of 2.5% of the total capital cost. The following power losses were assumed for thermal units:

Table 6.6.2 Assumed Power Losses for Thermal Power Plant

Item	kW	kWh
Power loss through transmission line	1.5 %	1.2 %
Forced operation outage	13.0 %	17.0 %
Maintenance outage	5.0 %	2.5 %
Consumption at power station	2.7 %	5.0 %

Replacement costs of thermal units were scheduled to be incurred at 20 years intervals for gas turbine and at 25 years for combined cycle. These results were shown in the explained Table 6.3.10.

6.6.4 RISK ANALYSIS

The result for the FSL.320m Alternative is 17.5% in the economic internal rate of return. The Project was then tested against probable risks associated with the project in following cases: (a) 10% up cost overrun, (b) alternative fuel price down by 20%, (c) project delay by one year, and (d) O&M cost increased by 20%.

Table 6.6.3 Results of Risk Analysis

No.	Risk Analysis	EIRR (%)
1.	Base Case	17.5%
2.	(a) 10% Increase in Investment Cost	15.7%
3.	(b) Alternative Fuel Price Down by 20%	14.9%
4.	(c) Project Delay by One Year	15.9%
5.	(d) O&M Cost Increase by 20%	17.4%

6.7 FINANCIAL EVALUATION

6.7.1 GENERAL

Analysis for the project financial justification is an evaluation of the project economics on an administrative standpoint of the Project. Since the project is planned as a business enterprise financed by international financial agencies such as ADB, World Bank, ECA, IFC, OECF etc. with its revenue given from electric power, water supply, etc., certainty of repayment of the project fund, therefore, has to be justified by the financial analysis.

The financial analyses of the Project is based on the assumption that the scheme will be owned and operated by a commercial company that will supply to the Thai national grid all the energy generated. The grid is assumed to be operated by EGAT or the future transmission company, which will purchase all the energy at a technically and economically acceptable point (at 500kV level). The tariff, as well as other relevant parameters for financial analyses, is determined based on two principles: (i) the project must be profitable, and (ii) the tariff level should be no higher than that paid by EGAT to IPPs in Thailand.

6.7.2 ASSUMPTIONS FOR FINANCIAL ANALYSIS

Financial analysis was made separately for two schemes of FSL.320m and FSL.360m. Projections of financial statements are made in nominal terms. Major assumptions made for financial analysis are given below:

The financial projections are based on a uniform escalation rate of 2.5% for foreign currency. And, construction work will start in 2006 and will be completed in 2010, requiring 5 years to complete as shown in Table 6.7.1. Commercial operation is expected to start in early 2011 with the working capital as shown in Table 6.7.2.

Table 6.7.1 Project Cost Disbursement Schedule

Year	2006	2007	2008	2009	2011
Disbursements with % of total project cost	10%	20%	35%	20%	15%

Table 6.7.2 Working Capital

No.	Items	Conditions
1.	Accounts receivables	1.5 months of revenue
2.	Cash required	2 % of revenue
3.	Accounts payable	1 month of O&M costs
4.	Escrow account	6 month of debt service

All electricity generated by the Project will be sold in bulk to EDL and EGAT under a 25-year power purchase agreement (PPA). The power generation and sales schedule is shown in Table 6.7.3.

Table 6.7.3 Power Generation and Sales Schedule (GWh/year)

Power Generation	EL.320m Scheme	EL.360m Scheme
Gross generation	1,349	1,905
Sales to EDL & EGAT	1,342	1,895

Note: Station use factor = 0.5%

The plant will be operated and maintained by a well-trained in-house staff or a world-reputed operating company under an Operating and Maintenance Agreement. The annual cost of such arrangement is estimated at 1% of base cost for each scheme, with an annual escalation of 2.5%.

According to a typical project agreement, Lao Government will grant the project company the right to construct and operate the project facilities and the right to use the land water rights necessary for the project. In return, the project company will pay the Government an annual royalty fee of 5% of gross revenues from electricity sales. Depreciation is assumed to be 4% per annum (straight-line for 25 years) on all depreciable assets.

Tax was considered as follows:

(i) Taxes and duties on imported capital equipment, if any, are assumed to be paid by EDL.

(ii) The Project will be exempted from income tax for the first 5 years of operation. Thereafter, tax on net income will be paid at a rate of 15%.

The equity capital is assumed to be 32% of the project cost according to current financial practices. Equity capital is assumed to be fully paid prior to disbursement of the bank loans except for OECF loan according to the likely loan covenants. The expected loan terms are given in Table 6.7.4.

Table 6.7.4 Financing Terms

Source	Interest (%)	Grace Period (years)	Maturity (years)	Commitment Fee (%)	Front-end Fee (%)
1. OECF	3.3	5	20	0.0	0.0
2. JCB	8.5	3	8	0.5	1.0
3. ADB	8.5	3	15	1.0	1.0
4. IFC	0.0	0	0	0.0	0.0
5. TCB	10.0	3	8	1.0	1.0

Note: OECF : Overseas Economic Corporation Fund
JCB : Japanese commercial banks
ADB : Asian Development Bank
IFC : International Finance Corporation
TCB : Thai Commercial Bank

A flat, 25 years depreciation rate is assumed. The concession period is 25 years and after 25 years, the project will be reverted to the GOL.

Deposit rate on cash on hand and the escrow account is assumed to be 2.5% per annum. Escrow account and dividends are considered as follows:

(i) The debt service coverage ratio shall be 1.4 or more.

(ii) The dividends are assumed to be paid at 80% of the net profit from 5th year of operation as far as the requirement of above (i) be met.

Parameters initially set for financial analysis are summarized and shown in Table 6.7.5 for FSL.320m.

Table 6.7.5 Initial Assumptions in Financial Analysis

No	Item	Amount		Remarks
1.	Construction Period	5	years	
2.	Project Life	30	years	
3.	Tariff	Peak Power	Off-Peak Power	
	(1) Initial tariff (c/kWh)	6.6	0	
	(2) Escalation rate	2.5%	0	
4.	O&M Costs			
	(1) Initial Cost (%)	1.0%	of Base cost	
	(2) Escalation rate	2.5%		
5.	Loyalty fee	5.0%		5% of revenue
6.	Depreciation	430.3	Mil.$ (FSL.320m)	Depreciable assets value
		577.1	Mil.$ (FSL.360m)	
	(1) Useful life	25	years	
	(2) Residual value	0%		
	(3) Method		Straight-line	
7.	Escrow account	50%		50% of annual debt service
8.	O&M reserve account	0%		
9.	Cash required	2%		2% of revenue
10.	Accounts receivable	12.5%		1.5 month of revenue
11.	Supplies and spares	0%		
12.	Accounts payable	8%		1 month of O&M Cost
13.	Deposit rate	2.5%	per annum	
14.	Income tax	15%	from 6th year of operation	
15.	Dividend rate	80%	of Net Profit from 5th year of operation	

6.7.3 BENEFITS ASSUMED FOR FINANCIAL ANALYSIS

The energy generated and supplied, net of line loss and auxiliary use, is assumed to be 766GWh for mid-peak energy (16-hr/day and 6-day/week) and 576GWh for off-peak energy for FSL.320m Alternative, while 1,082GWh for mid-peak energy and 813GWh for off-peak energy for FSL.360m Alternative. An initial tariff of 6.6 cents/kWh in 2011 the date of commissioning is assumed as levelised tariff and will increase with an annual escalation of 2.5 %.

Based on the rules setup by the government policy, the following three-step tariff structure has been assumed:

Table 6.7.6 Primary Levelised Energy Tariff at Current Price

Step	Years	Period	Tariff in 1999 (USc/kWh)	Tariff in 2011 (USc/kWh)
1st	1-12	12	4.7	6.6
2nd	13-22	10	4.3	6.3
3rd	23-25	3	4.7	6.6
Weighted Average			4.7	6.6

During the first 12 years, the tariff will be slightly higher to cover the loan repayment and to insure a reasonable level of profit to the investors. In the next 10 years, the tariff will be brought down after the loan repayment requirement is eased. The tariff will then return to its initial level just before the project is supposed to be reverted to the government.

The EGAT's purchase price from other projects can be used here as a reference to our tariff calculation. For the use of national resources, GOL charges a royalty at 5% of gross revenue. Corporate income tax is also levied on the net profit at a rate of 15%. However, to attract foreign investors, a tax holiday is usually provided. In this case, first 5 years starting at COD is assumed.

Table 6.7.7 Tariff Comparison

No.	Simple Model	Theun-Hinboun	Hong Sa	Xp-Xn
1.	Base Tariff (USc)	4.3	6.4	4
2.	Before COD escalation (%)	3.0	-	3.0
3.	Post COD escalation (%)	1.0	-	1.0
4.	COD date (Year)	1999	2001	2007
5.	Tariff at 1999 level or COD level	4.99 (1999)	6.4 (2001)	-
No.	Stepped Model	Nam Ngum 3	Nam Ngiep	
1.	1st Step Tariff (USc)	5.98	6.7	
2.	Years of 1st Step	12 yrs	12 yrs	
3.	2nd Step Tariff (USc)	4.2	6.3	
4.	COD date (Year)	-	2011	
5.	1st Step Tariff at 1999 Level	-	4.7	

6.7.4 FINANCIAL EVALUATION OF FSL.320M ALTERNATIVE

FSL.320m Alternative of which project cost is US$385.2 million excluding IDC, FSL is EL.320m, plant capacity is 240MW, annual energy is 1,349GWh, assumes a joint venture between GOL and a consortium of private sectors. An independent BOT power development company is assumed in this model and the debt-equity ratio of 65-35 is used. The GOL would be responsible for 25% of equity investment, and the GOL equity is assumed to come from an international soft loan.

The financial IRR obtained for FSL.320m Alternative is 12.8% as FIRR on Project and annual net benefit (NPV) is assumed to be US$79.8million (NPV). Disbursement of the Project cost for FSL.320m Alternative is as shown in Table 6.7.8.

Table 6.7.8 Disbursement of Project Cost

Year	2006	2007	2008	2009	2010	2011	Total
1. Disbursement of Base	Cost						
(1) Ratio	10.0%	20.0%	35.0%	20.0%	15.0%	0.0%	100.0%
(2) Amount (Mil.$)	38.5	77.0	134.8	77.0	57.8	0.0	385.2
2. Equity							
(1) Ratio	28.6%	45.0%	26.4%	0.0%	0.0%	0.0%	100.0%
(2) Amount (Mil.$)	38.6	60.7	35.6	0.0	0.0	0.0	134.8
3. Loan (Mil.$)	0.0	16.4	99.2	77.0	57.8	0.0	250.4
(1) OECF	0.0%	18.0%	47.0%	35.0%	0.0%	0.0%	100.0%
-Disburse.	0.0	15.8	41.2	30.7	0.0	0.0	87.6
-Interest		0.0	0.5	1.9	3.0	3.1	8.5
-Total	0.0	15.8	41.7	32.6	3.0	3.1	96.1
(2) JCB	0.0%	0.0%	46.8%	28.5%	24.7%	0.0%	100.0%
-Disburse.	0.0	0.0	41.0	25.0	21.6	0.0	87.6
-Interest		0.0	0.0	3.5	5.9	8.2	17.6
-Total	0.0	0.0	41.0	28.5	27.6	8.2	105.3
(3) ADB	0.0%	0.0%	46.8%	28.6%	24.6%	0.0%	100.0%
-Disburse.	0.0	0.0	17.6	10.7	9.2	0.0	37.6
-Interest		0.0	0.0	1.5	2.5	3.5	7.6
-Total	0.0	0.0	17.6	12.2	11.8	3.5	45.1
(4) IFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
-Disburse.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Interest		0.0	0.0	0.0	0.0	0.0	0.0
-Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) TCB	0.0%	0.0%	0.0%	28.5%	71.5%	0.0%	100.0%
-Disburse.	0.0	0.0	0.0	10.7	26.9	0.0	37.6
-Interest		0.0	0.0	0.0	1.1	3.9	4.9
-Total	0.0	0.0	0.0	10.7	27.9	3.9	42.5
4. Loan Total							
-Disburse.	0.0	15.8	99.8	77.1	57.7	0.0	250.4
-Interest	0.0	0.0	0.5	6.9	12.5	18.7	38.6
-Total	0.0	15.8	100.3	84.0	70.2	18.7	289.0
5. Equity & Loan	38.6	76.4	135.9	84.0	70.2	18.7	423.8
6. Front-end Fee							
(1) OECF	0.0	-	-	-	-	-	0.0
(2) JCB	1.1	-	-	-	-	-	1.1
(3) ADB	0.5	-	-	-	-	-	0.5
(4) IFC	0.0	-	-	-	-	-	0.0
(5) TCB	0.4	-	-	-	-	-	0.4
Total	1.9	0.0	0.0	0.0	0.0	0.0	1.9
7. Comitm't Fee							
(1) OECF		0.0	0.0	0.0	0.0	0.0	0.0
(2) JCB		0.5	0.5	0.3	0.2	0.0	1.6
(3) ADB		0.5	0.5	0.3	0.2	0.0	1.4
(4) IFC		0.0	0.0	0.0	0.0	0.0	0.0
(5) TCB		0.4	0.4	0.4	0.3	0.0	1.6
Total	0.0	1.4	1.4	1.0	0.6	0.1	4.6
Grand Total	40.5	77.8	137.3	85.0	70.9	18.8	430.3

(Euity) / (Equity+Loan+Interest) Ratio =31%

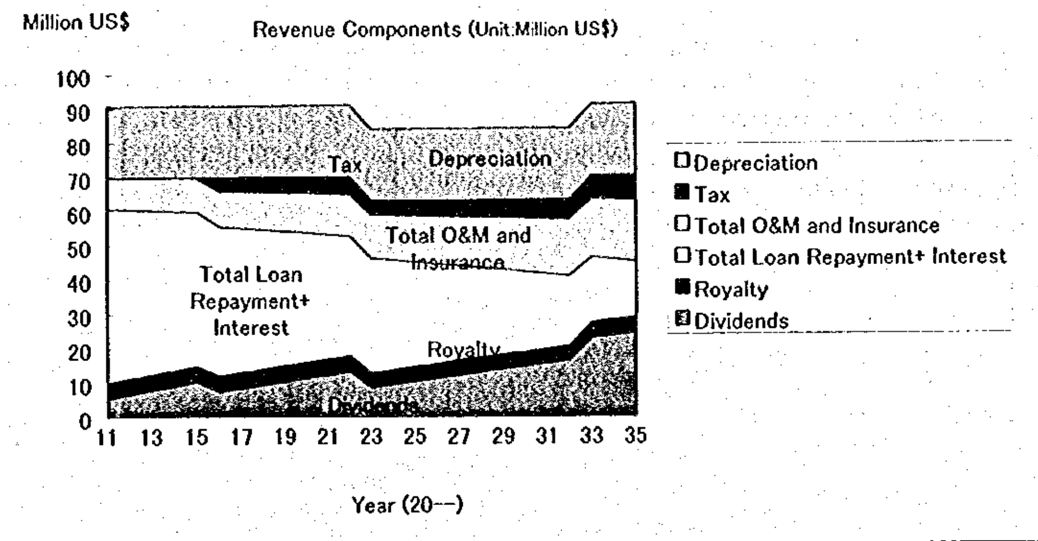


Figure 6.7.1 Revenue Components of FSL.320mAlternative

6.7.5 FINANCIAL EVALUATION OF FSL.360M ALTERNATIVE

FSL.360m Alternative of which project cost is US$516.6 million excluding IDC, FSL is EL.360m, plant capacity is 334MW, annual energy is 1,905GWh.

The financial IRR (FIRR) obtained for FSL.360m Alternative is 13.7% as FIRR on Project and annual net benefit is assumed to be US$143.7million (NPV).

6.7.6 SENSITIVITY ANALYSIS FOR BOTH ALTERNATIVES

Sensitive analysis was made for the following cases:

(i) 10% increase of Base Cost

(ii) 10% decrease of Annual Energy Generation

Delay of the project completion was not considered, because enough 5-year period was taken for construction.

A sensitivity analysis of FIRR was carried out for both FSL.320m and FSL.360m Alternatives to test the risks involved in the project. The results are favorable as shown in Table 6.7.9 below.

Table 6.7.9 Results of Sensitivity Analysis

No.	Risk Analysis	FSL.320m	FSL.360m
1.	Base Case	12.8%	13.7%
2.	10% Increase in Investment Cost	11.6%	12.5%
3.	10% Decrease in Total Energy Sales	11.4%	12.3%

The financial IRR obtained for FSL.320m Alternative is 12.8% as FIRR on Project and annual net benefit (NPV) is assumed to be US$79.8million (NPV). Disbursement of the Project cost for FSL.320m Alternative is as shown in Table 6.7.8.

Table 6.7.8 Disbursement of Project Cost

Year	2006	2007	2008	2009	2010	2011	Total
1. Disbursement of Base	Cost						
(1) Ratio	10.0%	20.0%	35.0%	20.0%	15.0%	0.0%	100.0%
(2) Amount (Mil.$)	38.5	77.0	134.8	77.0	57.8	0.0	385.2
2. Equity							
(1) Ratio	28.6%	45.0%	26.4%	0.0%	0.0%	0.0%	100.0%
(2) Amount (Mil.$)	38.6	60.7	35.6	0.0	0.0	0.0	134.8
3. Loan (Mil.$)	0.0	16.4	99.2	77.0	57.8	0.0	250.4
(1) OECF	0.0%	18.0%	47.0%	35.0%	0.0%	0.0%	100.0%
-Disburse.	0.0	15.8	41.2	30.7	0.0	0.0	87.6
-Interest		0.0	0.5	1.9	3.0	3.1	8.5
-Total	0.0	15.8	41.7	32.6	3.0	3.1	96.1
(2) JCB	0.0%	0.0%	46.8%	28.5%	24.7%	0.0%	100.0%
-Disburse.	0.0	0.0	41.0	25.0	21.6	0.0	87.6
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-Disburse.	0.0	0.0	17.6	10.7	9.2	0.0	37.6
-Interest		0.0	0.0	1.5	2.5	3.5	7.6
-Total	0.0	0.0	17.6	12.2	11.8	3.5	45.1
(4) IFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
-Disburse.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Interest		0.0	0.0	0.0	0.0	0.0	0.0
-Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) TCB	0.0%	0.0%	0.0%	28.5%	71.5%	0.0%	100.0%
-Disburse.	0.0	0.0	0.0	10.7	26.9	0.0	37.6
-Interest		0.0	0.0	0.0	1.1	3.9	4.9
-Total	0.0	0.0	0.0	10.7	27.9	3.9	42.5
4. Loan Total							
-Disburse.	0.0	15.8	99.8	77.1	57.7	0.0	250.4
-Interest	0.0	0.0	0.5	6.9	12.5	18.7	38.6
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(3) ADB	0.5	-	-	-	-	-	0.5
(4) IFC	0.0	-	-	-	-	-	0.0
(5) TCB	0.4	-	-	-	-	-	0.4
Total	1.9	0.0	0.0	0.0	0.0	0.0	1.9
7. Comitm't Fee							
(1) OECF		0.0	0.0	0.0	0.0	0.0	0.0
(2) JCB		0.5	0.5	0.3	0.2	0.0	1.6
(3) ADB		0.5	0.5	0.3	0.2	0.0	1.4
(4) IFC		0.0	0.0	0.0	0.0	0.0	0.0
(5) TCB		0.4	0.4	0.4	0.3	0.0	1.6
Total	0.0	1.4	1.4	1.0	0.6	0.1	4.6
Grand Total	40.5	77.8	137.3	85.0	70.9	18.8	430.3

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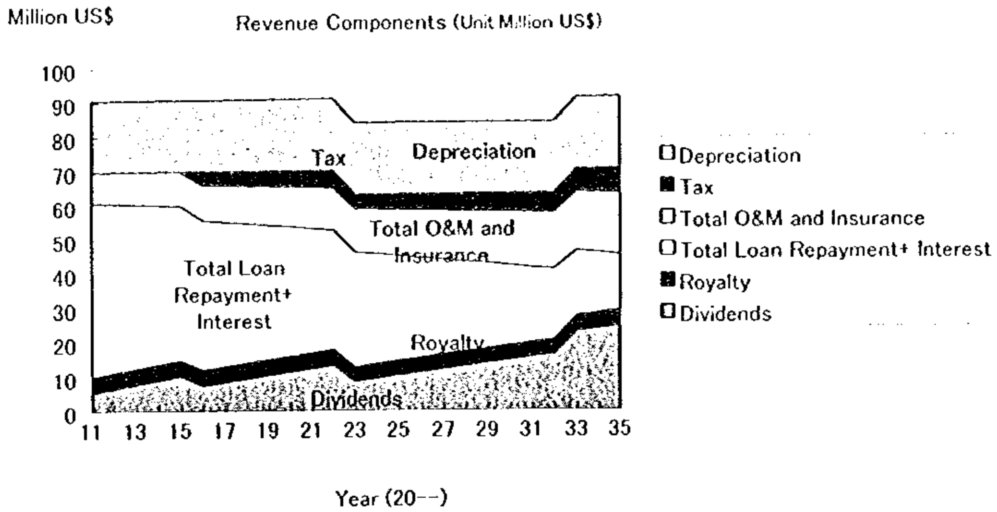

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3.	10% Decrease in Total Energy Sales	11.4%	12.3%

6.7.7 CONCLUSIONS

Both FSL.320m and FSL.360m Alternatives are financially viable under the conservative conditions following the current actual economic conditions, since their FIRRs are over 12%. However, FSL.360m Alternative of a larger output is more competitive than FSL.320m one with the different FIRR of about one (1) point only. Consequently, as a conclusion, the basic data for the economic evaluation, such as a topography, geology and hydrology are not enough to determine the final selection of the dam height.