CHAPTER 9

ECONOMIC EVALUATION AND FINANCIAL ANALYSIS

CHAPTER 9 ECONOMIC EVALUATION AND FINANCIAL ANALYSIS

This Project envisages construction of the high voltage DC transmission line and the 138 kV AC transmission line, including AC-DC converter stations, as the main distributing system for power transmission of geothermal energy to be produced at Tongonan to the consuming area in Luzon Island.

The substantial aim of economic evaluation is to assess if the proposed plan for the Project can make more effective use of the capital than its alternative plan can do. From the financial aspect, it is obvious that the proposed system would not produce any profitable return independently from the invested capital, since the system is planned merely as the means of power transmission from one end to the other. Therefore, such analysis is made by comparison between incomes from power sales in Manila as the consuming center and the costs required for power service in that area, including necessary costs for conversion of geothermal energy into electricity at Tongonan.

9.1 Economic Evaluation

As stated earlier in Item 5.3 of Chapter 5, the alternative system comparable to the HVDC system would be both of AC 500 kV and AC 230 kV transmission systems. However, the Survey Team has excluded the AC 500 kV transmission plan from this economic comparative study because of its undoubtedly higher construction costs and

taken up the other 230 kV transmission plan as the alternative to the HVDC for comparison.

9.1.1 Fundamental Consideration for Economic Comparison

The working area under this Project ranges over a distance of 455 km from Tongonan Switch Yard to Naga Conversion Station. In fact, however, since Manila in Luzon Island is the consuming center of electric energy to be produced at Tongonan, the economic comparative study should theoretically cover all necessary construction costs for power transmission over a total length of 789 km from Tongonan to San Jose Substation situated in the suburbs of Manila. Nevertheless, the comparative study does not include the construction cost for the 500 kV transmission line between San Jose Substation and Naga Converter Station, since its construction becomes a common cost factor to either one of the HVDC plan or the AC 230 kV plan. It is noted, however, that the AC 230 kV transmission plan should require operation of the said line at its designed voltage of 500 kV from the beginning while the HVDC plan contemplates to boost up to the full rating of 500 kV later by 1991. Therefore, the time lag in boosting up voltage as proposed is taken into account in the evaluation by construction cost comparison. Furthermore, possible difference in transmission energy loss between the two alternatives is also taken into economic evaluation.

(1) Scope of costs for economic evaluation

Since the cost comparison as shown in Table 5-4 of Chapter 5 shows direct construction costs only, annual cash flow has been projected, as shown in Table 9-1, by inclusion of necessary indirect costs (but not including interest during construction).

(2) Power and energy loss evaluation

This Project aims at power development in Luzon to take place of the existing oil-fueled thermal power plants. In other works, the oil-fueled power plants can be left out of operation by transmission of geothermal energy from Tongonan to the consuming center in and around Manila. In this sense, economic evaluation includes transmission loss only in terms of kWh energy, not including loss in kW. The oil fuel price is based upon the price level as of March 1981, the basic time point for this economic evaluation.

Energy loss cost : 50 U.S. mills per kWh

Where, 32.0 U.S. dollars per barrel

(3) Opportunity cost of capital and discount rate

For economic evaluation of this Project the discount rate is predetermined at 10 percent as mutually agreed by consultation with NAPOCOR. This discount rate is regarded as

Table 9-1 Economic Evaluation of the Project
(Economic Cost)

	HVDC			AC 230 kV		
	Capital Cost		O & M	Capital Cost		O & M
	1st Stage	2nd Stage	Cost	1st Stage	2nd Stage	Cost
1982	2.3			2.2		
83	32.8			91.4		
84	161.0			199.6		
85	43.3			43.8		
86			5.4			7.1
87			5.4			7.1
88		36.8	5.4		36.7	7.1
89		92.0	5.4		91.8	7.1
90		55.1	5.4		55.0	7.1
91			7.8			11.2
92			7.8			11.2
93			7.8			11.2
94			7.8			11.2
Total	239.4	183.9		337.0	183.5	

Note	HVDC		AC 230 kV	
	1982-1985	1988-1990 *	1982-1985 *	1988-1990
- Direct cost	213.0	172.0	307.0	167.0
- Physical contingency	16.0	7.0	23.0	12.5
- Engineering & adm.	10.2	4.5	7.0	4.0
- NPC's Eng. education	0.2	0.1	0	0
Total	239.4	183.9	337.0	183.5

Note * including voltage step-up costs from AC 230 kV to AC 500 kV.

the opportunity cost as viewed on the capital side and is normally the expected minimum rate of return for a project when financed by the I.B.R.D.

With this taken into account, cost comparison is made between the two alternatives after the projected cash flow for both HVDC plan and AC 230 kV plan has been discounted by the opportunity cost of capital.

(4) Period for evaluation

The proposed system under this Project constitutes various components of electric facilities with different durable service-life length. The durable life for Tongonan geothermal power facilities is stipulated at 20 years. With this stipulated period in mind, the period for economic evaluation has been set at 30 years, as previously accepted between NAPOCOR and the Survey Team.

9.1.2 Conclusion from Economic Evaluation

As shown in Table 9-2, evaluation has been made for comparison between the HVDC plan and the AC 230 kV plan by applying the discount rate of 10 percent as the capital opportunity cost to the cash flow inclusive of construction, operation, maintenance and energy loss costs. As the result, the benefit-cost ratio has been attained as follows:

Table 9-2 Economic Evaluation of the Project

n	Year	Discounted rate i=10%	Available supply energy (GWh)	*1 COST OF HVDC							*2 BENEFIT = COST OF AC 230 kV						
				Loss factor (%)	Loss energy (GWh)	Capital investment (10^6US$)	O & M cost (10^6US$)	Loss cost (10^6US$)	Total cost (10^6US$)	Present value (10^6US$)	Loss factor (%)	Loss energy (GWh)	Capital investment (10^6US$)	O & M cost (10^6US$)	Loss cost (10^6US$)	Total cost (10^6US$)	Present value (10^6US$)
-4	1982	1.331				2.3			2.3	3.1			2.2			2.2	2.9
-3	1983	1.210				32.8			32.8	39.7			91.4			91.4	102.4
-2	1984	1.100				161.0			161.0	177.1			199.6			199.6	219.6
-1	1985	1.000				43.3			43.3	43.3			43.8			43.8	43.8
1	1986	0.909	3.338	11.6	387	0	5.4	19.3	24.7	22.5	5.5	184	0	7.1	9.2	16.3	14.8
2	1987	0.826	3.323	11.6	385	0	5.4	19.2	24.6	20.3	5.5	183	0	7.1	9.2	16.3	13.5
3	1988	0.751	3.305	11.6	383	36.8	5.4	19.1	61.3	46.0	5.5	182	36.7	7.1	9.1	52.9	39.7
4	1989	0.683	3.286	11.6	381	92.0	5.4	19.0	116.4	79.5	5.5	181	91.8	7.1	9.1	108.0	73.8
5	1990	0.620	3.263	11.6	378	55.1	5.4	18.9	79.4	49.2	5.5	179	55.0	7.1	9.0	71.1	44.1
6	1991	0.564	4.832	7.7	371	0	7.8	18.5	26.3	14.8	6.1	295	0	11.2	14.8	26.0	14.7
7	1992	0.513	6.392	8.4	936	0	7.8	26.8	34.6	17.7	7.5	479	0	11.2	24.0	35.2	18.1
8	1993	0.466	7.165	9.2	659	0	7.8	32.9	40.7	19.0	8.5	609	0	11.2	30.5	41.7	19.4
9	1994	0.424	7.137	9.2	656	0	7.8	32.8	40.6	17.2	8.5	07	0	11.2	30.4	41.6	17.6
10	1995	0.385	7.100	9.2	653	0	7.8	32.6	40.4	15.6	8.5	604	0	11.2	30.2	41.4	15.9
11	1996	0.350	7.100	9.2	653	0	7.8	32.6	40.4	14.1	8.5	604	0	11.2	30.2	41.4	14.5
12	1997	0.318	7.100	9.2	653	0	7.8	32.6	40.4	12.8	8.5	604	0	11.2	30.2	41.4	13.2
13	1998	0.289	7.100	9.2	653	0	7.8	32.6	40.4	11.7	8.5	604	0	11.2	30.2	41.4	12.0
14	1999	0.263	7.100	9.2	653	0	7.8	32.6	40.4	10.6	8.5	604	0	11.2	30.2	41.4	10.9
15	2000	0.239	7.100	9.2	653	0	7.8	32.6	40.4	9.7	8.5	604	0	11.2	30.2	41.4	9.9
16	2001	0.217	7.100	9.2	653	0	7.8	32.6	40.4	8.8	8.5	604	0	11.2	30.2	41.4	9.0
17	2002	0.197	7.100	9.2	653	0	7.8	32.6	40.4	8.0	8.5	604	0	11.2	30.2	41.4	8.2
18	2003	0.179	7.100	9.2	653	0	7.8	32.6	40.4	7.2	8.5	604	0	11.2	30.2	41.4	7.4
19	2004	0.163	7.100	9.2	653	0	7.8	32.6	40.4	6.6	8.5	604	0	11.2	30.2	41.4	6.7
20	2005	0.148	7.100	9.2	653	0	7.8	32.6	40.4	6.0	8.5	604	0	11.2	30.2	41.4	6.1
21	2006	0.135	7.100	9.2	653	0	7.8	32.6	40.4	5.5	8.5	604	0	11.2	30.2	41.4	5.6
22	2007	0.122	7.100	9.2	653	0	7.8	32.6	40.4	4.9	8.5	604	0	11.2	30.2	41.4	5.1
23	2008	0.111	7.100	9.2	653	18.6	7.8	32.6	59.0	6.5	8.5	604	24.3	11.2	30.2	65.7	7.3
24	2009	0.101	7.100	9.2	653	46.6	7.8	32.6	87.0	8.9	8.5	604	40.5	11.2	30.2	81.9	8.3
25	2010	0.092	7.100	9.2	653	27.9	7.8	32.6	68.3	6.3	8.5	604	16.2	11.2	30.2	57.6	5.3
26	2011	0.083	7.100	9.2	653	0	7.8	32.6	40.4	3.4	8.5	604	0	11.2	30.2	41.4	3.4
27	2012	0.076	7.100	9.2	653	0	7.8	32.6	40.4	3.1	8.5	604	0	11.2	30.2	41.4	3.1
28	2013	0.069	7.100	9.2	653	14.1	7.8	32.6	54.5	3.8	8.5	604	9.0	11.2	30.2	50.4	3.5
29	2014	0.063	7.100	9.2	653	35.3	7.8	32.6	75.7	4.8	8.5	604	22.5	11.2	30.2	63.9	4.0
30	2015	0.057	7.100	9.2	653	21.1	7.8	32.6	61.5	3.5	8.5	604	13.5	11.2	30.2	54.9	3.1
										711.2							786.9

Note : *1, 2 These figures mean transmission lines from Tongonan S/Y to San Jose S/S
: Energy loss cost = 50 US mills/kWh B/C = 786.9/711.2 = 1.106

B = Benefit (Cost for AC 230 kV) : 786.9 x 10^6 US$

C = Cost (Cost for HVDC) : 711.2 x 10^6 US$

Then, B/C = 786.9 x 10^6 US$/711.2 x 10^6 US$

= 1.106

Incidentally, the AC 230 kV transmission plan should require ultimately three (3) routes for its increased number of circuits, which would further increase the construction cost, as a matter of actual practice, solely because of land acquisition for the right-of-way expansion and would accordingly make the foregoing B/C ratio greater than computed here. Then, the economy of the HVDC plan would become larger without question.

9.2 Financial Analysis

A vast sum of investment is required for transmission of bulk power over a long distance as contemplated under this Project. Investment requires several years of construction and the return from such investment can only begin after several years from the time of investment. The durable service life of the completed facilities is considerably longer than that of the general equipment. This means that both capital and interest must be redeemed inevitably over a long term out of the revenue to be earned from and after such investment.

Therefore, it can be said that the essential condition to the construction of power facilities is to finance the project with the borrowing fund available at a low interest rate on a long-term payment basis with a long grace period. It seems, however, that the availability of local financing in the Philippines may be difficult to satisfy such requirements as required vast sum of investment at low interest rate and over long term of repayment. In spite of this prospect for local financing arrangements, the usual pattern is that all the local currency portion is procured from the borrower's own financing sources, though any foreign currency portion required for implementation of the Project can be borrowed through the arrangement of development aid from government to government or from the international financing institutions such as I.B.R.D or A.D.B as is normally the case extended to the power development project in developing countries.

9.2.1 Fundamental Consideration for Financial Analysis

The financial analysis is to seek the income from total revenue of salable electric energy multiplied by tariff rates at San Jose Substation in the consuming center with regard to geothermal energy produced at Tongonan power plants and the expense which should cover the total project cost for EHV transmission construction plus a part of 500 kV transmission line construction cost, including power generating cost at Tongonan power plants. The generating cost at Tongonan is divided into steam cost for purchase from PNOC by NAPOCOR and investment cost for power generation.

In order to check the financial condition, sensitivities on the interest rate for the foreign money and average power rate are calculated.

(1) Financial analysis

Assuming that the project is undertaken by any other enterprise than NAPOCOR and the enterprise himself can make financing arrangements on the following conditions, the result of financial analysis is as follows:

a) Financing procurement conditions

Foreign currency portion:

Interest rate : 4, 6, 8, 10% per year

Terms of repayment: 30 years (including 10-year grace period)

Local currency portion:

The Philippine Government is contribution without specific conditions of repayment

b) Power tariff rate

65, 70, 75, 80 US mills per kWh are assumed to keep for 20 years after commencement of the project.

c) Operating expenses

The operating expenses should include operating and maintenance costs and depreciation cost to arise from the allocated portion of construction cost for the AC 500 kV transmission line. Those costs are summarized in Table 9-3 and Table 9-4.

d) Generating cost of Tongonan Geothermal Power Plant

The power generating cost consists of both steam cost for purchase from PNOC by NAPOCOR and power plant cost. The power plant cost is shown in Table 9-5. The steam cost is estimated at 35 US mill per kWh, same as used for economic evaluation.

Table 9-3 DC ± 350 kV Transmission Line Cost

Unit : 10^6 US$

Year	* Economic Cost			* Financial Cost		
	Capital Investment	O & M Cost	Total Cost	Capital Investment	O & M Cost	Total Cost
1982	2.3		2.3	2.6		2.6
1983	31.9		31.9	40.6		40.6
1984	160.0		160.0	221.6		221.6
1985	42.3		42.3	71.3		71.3
1986		5.4	5.4		8.1	8.1
1987		5.4	5.4		8.7	8.7
1988	9.2	5.4	14.6	16.9	9.3	26.2
1989	73.7	5.4	79.1	153.7	9.9	163.6
1990	19.9	5.4	25.3	57.0	10.6	67.6
1991		7.8	7.8		16.0	16.0
1992		7.8	7.8		16.0	16.0
1993		7.8	7.8		16.0	16.0
Total	339.3	50.4	389.7	563.7	94.6	658.3

Note : Without interest during construction

Table 9-4 AC 500 kV Transmission Line Allocated Cost
(Naga - San Jose)

Year	Allocated Capital Investment (10^6 US$)	Allocated O & M Cost (10^6 US$)	Total Cost (10^6 US$)
1982	2.0		2.0
1983	24.3		24.3
1984	60.7		60.7
1985	36.1		36.1
1986		3.1	3.1
1987		3.3	3.3
1988		3.5	3.5
1989		3.8	3.8
1990		4.1	4.1
1991		4.1	4.1
1992		4.1	4.1
1993		4.1	4.1
Total	123.1	30.1	153.2

Naga - Kalayaan : 237 km
Kalayaan - San Jose : 97 km

Total 334 km

Justifiable expenditure :

Construction cost of ± 350 kV DC Line without submarine cables

149.6×10^6 US$/406 km x 334 km = 123.1×10^6 US$

O & M cost

$123.6 \times 0.025 \times 10^6 = 3.1 \times 10^6$ US$

Table 9-5 Power Plant Cost for Tongonan & Others
(Financial Cost)

Year	Installed Capacity (MW)	Capital Investment (10^6 US$)	O & M Cost (10^6 US$)	Total Cost (10^6 US$)	Remarks
1983		84.0		84.0	
1984		209.0		209.0	
1985		125.0		125.0	
1986	440 MW		10.5	10.5	No. 4 to No. 11
1987			11.2	11.2	
1988		62.0	12.0	74.0	
1989		218.7	12.8	231.5	
1990		281.6	13.7	295.3	
1991	220 MW	172.0	21.5	193.5	No. 12 to No. 15
1992	220 MW	46.7	29.3	76.0	No. 16 to No. 19
1993	110 MW		33.2	33.2	No. 20 to No. 21
Total	990 MW	1,199.0	144.2	1,343.2	

Unit construction cost : 725 US$/kW at 1981 price

725 x 1.31 = 950 US$/kW for Unit No. 4 to No. 11

725 x 1.96 = 1,420 US$/kW for unit No. 12 to 21.

Operation and maintenance cost :

Construction cost x 0.025

Both income statement and cash flow statement as estimated from the foregoing conditions are summarized in Table 9-6, 9-7, 9-8 and Table 9-9, respectively.

9.2.2 Conclusion from Financial Analysis

This Project requires a total sum of 352.4 million U.S. dollars including possible price escalation for the 1st. Stage construction terminating by end of 1985. It is recommended that the foreign currency portion of 243.2 million U.S. dollars to be required for the 1st. Stage construction should be financed by the development aid fund of long-term repayment, low interest on the government-to-government basis while the local currency portion should be financed by the Philippine Government.

For the 2nd Stage construction work, the internal reserve fund accumulated from the operating income will be made available and no domestic fund will be required from the Philippine Government as far as the local currency portion is concerned.

This Project is essential to transmitting geothermal energy from Tongonan to the load center in Luzon Island. Once the 1st. Stage construction work has been completed successfully, a part of the necessary fund for the 2nd Stage construction can be self-financed by the operating income.

(1) Income statement

In Table 9-6 Projected Income Statement and Return Rate base on the average power rate of 75 US mills/kWh is shown and it can be understood from the table that for the first a few years operation, it can allow return on the average plants in service ranging from 5 to 7% but for the remaining years difference should be recovered and must be above 8%. Further assuming different power rate of 70 and 65 US mills/kWh shown in Table 9-7, it will require 12 years and 24 years respectively to be better than the reasonable target of 8% of return.

(2) Cash flow statement

Cash flow for 25 years based on the interest rate of 6% per year for foreign fund borrowed is shown in Table 9-8 and it can be seen that the negative cash flows should be allowed for a few years after commencement of the project but after that it will turn to be positive and gradually increase cash.

Cash flow changes based on the various interest rate of the fund as shown in Table 9-9 and it shows that the low interest rate fund is preferable for this project.

Table 9-6 Projected Income Statement and Return Rate

Power Rate = 75 U.S. Mills

Year	Power Sales	Ave. Power Rate (U.S. Mills)	Operating Revenue	Trans. Lines Operation		Tongonan Steam	Generation Expense		Operating Income	Ave. Plant in Service	Return Ave. P.I.S.
				O & M Cost	Depreciation		O & M Cost	Depreciation			
1986	2957	75	221.33	11.2	11.98	116.8	10.5	16.72	54.13	763.25	7.09
1987	2938	75	220.35	12.0	11.98	116.3	11.2	16.72	52.15	734.55	7.10
1988	2922	75	219.15	12.8	11.98	115.7	12.0	16.72	49.95	705.85	7.08
1989	2905	75	217.88	13.7	11.98	115.0	12.8	16.72	47.68	677.15	7.04
1990	2885	75	216.38	14.7	11.98	114.2	13.7	16.72	45.08	648.45	6.95
1991	4461	75	334.58	20.1	15.41	168.8	21.5	29.22	79.55	1,026.99	7.75
1992	5856	75	439.20	20.1	15.41	223.7	29.3	41.72	108.97	1,288.51	8.46
1993	6501	75	487.58	20.1	15.41	250.8	33.2	47.97	120.10	1,384.46	8.67
1994	6481	75	486.08	20.1	15.41	249.9	33.2	47.97	119.50	1,321.08	9.05
1995	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	1,257.70	9.41
1996	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	1,194.32	9.91
1997	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	1,130.94	10.46
1998	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	1,067.56	11.09
1999	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	1,004.18	11.79
2000	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	940.80	12.58
2001	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	877.42	13.49
2002	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	814.04	14.54
2003	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	750.66	15.79
2004	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	687.28	17.22
2005	6447	75	483.53	20.1	15.41	248.5	33.2	47.97	118.35	623.90	18.97

Table 9-7 Sensitivity of Return Rate on Average Power Rate

Unit : %

Year \ Power Rate (US Mill/kwh)	65	70	75	80
1986	3.28	5.21	7.09	9.09
1987	3.10	5.10	7.10	9.10
1988	2.94	5.01	7.08	9.15
1989	2.75	4.90	7.04	9.19
1990	2.50	4.73	6.95	9.18
1991	3.40	5.57	7.75	9.92
1992	3.91	6.18	8.46	10.73
1993	3.98	6.33	8.67	11.02
1994	4.14	6.59	9.05	11.50
1995	4.28	6.85	9.41	11.97
1996	4.51	7.21	9.91	12.61
1997	4.76	7.61	10.46	13.31
1998	5.05	8.07	11.09	14.11
1999	5.37	8.58	11.79	15.00
2000	5.73	9.15	12.58	16.01
2001	6.14	9.81	13.49	17.16
2002	6.62	10.58	14.54	18.50
2003	7.18	11.47	15.79	20.06
2004	7.84	12.53	17.22	21.91
2005	8.64	13.80	18.97	24.13

Table 9-8 Projected Cash Flow Statement

Unit = 10^6 US$ Interest = 6%

Year	Income before Interest	Depreciation	Foreign Loan	Gov't Equity	Total Source	Capital Cost		Debt Service		Total Application	Increase in Cash	Cash at End
						F.C.	L.C.	Interest	Principal			
1982			2.5	0.1	2.6	2.5	0.1			2.6	0	0
1983			28.0	13.4	41.40	28.0	13.4	1.8		43.2	-1.8	-1.80
1984			165.6	61.3	226.90	165.6	61.3	11.8		238.7	-11.8	-13.60
1985			47.1	34.3	81.40	47.1	34.3	14.6		96.0	-14.6	-28.20
1986	54.13	28.70			82.83			14.6		14.6	68.23	40.03
1987	52.15	28.70			80.85			14.6		14.6	66.25	106.28
1988	49.95	28.70	14.6	0	93.25	14.6	0	15.5		30.1	63.15	169.43
1989	47.68	28.70	115.8	0	192.18	115.8	0	22.4		138.2	53.98	223.41
1990	45.08	28.70	30.2	0	103.98	30.2	0	24.2		54.4	49.58	272.99
1991	79.55	44.63			124.18			24.2	0.1	24.3	99.88	372.87
1992	108.97	57.13			166.10			24.2	1.5	25.7	140.40	513.27
1993	120.10	63.38			183.48			24.2	9.8	34.0	149.48	662.75
1994	119.50	63.38			182.88			23.5	12.1	35.6	147.28	810.03
1995	118.35	63.38			181.73			22.8	12.2	35.0	146.73	956.76
1996	118.35	63.38			181.73			22.1	12.2	34.3	147.43	1,104.19
1997	118.35	63.38			181.73			21.4	12.8	34.2	147.53	1,251.72
1998	118.35	63.38			181.73			20.6	18.7	39.3	142.43	1,394.15
1999	118.35	63.38			181.73			19.5	20.2	39.7	142.03	1,536.18
2000	118.35	63.38			181.73			18.3	20.3	38.6	143.13	1,679.31
2001	118.35	63.38			181.73			17.0	20.3	37.3	144.43	1,823.74
2002	118.35	63.38			181.73			15.8	20.3	36.1	145.63	1,969.37
2003	118.35	63.38			181.73			14.6	20.3	34.9	146.83	2,166.20
2004	118.35	63.38			181.73			13.4	20.3	33.7	148.03	2,264.23
2005	118.35	63.38			181.73			12.1	20.3	32.4	149.33	2,413.56
	1,978.96	1,069.20	403.8	109.1	3,561.06			413.2	221.4	1,147.5	2,413.56	

Table 9-9 Sensitivity of "Increase in Cash" on the Interest Rate

Unit : 10^6 US$

Year \ Interest Rate (%)	4	6	8	10
1982	0	0	0	0
1983	-1.2	-1.8	-2.4	-3.1
1984	-7.8	-11.8	-15.7	-19.6
1985	-9.7	-14.6	-19.5	-24.3
1986	73.1	68.2	63.3	58.5
1987	71.2	66.2	61.4	56.6
1988	68.4	63.2	58.1	52.9
1989	61.5	54.0	46.5	39.0
1990	57.6	49.6	41.5	33.4
1991	107.9	99.9	91.8	83.7
1992	148.4	140.4	132.3	124.2
1993	157.6	149.5	141.5	133.5
1994	155.1	147.3	139.4	131.6
1995	154.3	146.7	139.1	131.5
1996	154.8	147.4	140.1	132.7
1997	154.7	147.5	140.4	133.3
1998	149.3	142.4	135.6	128.7
1999	148.5	142.0	135.5	129.1
2000	149.2	143.1	137.1	131.0
2001	150.0	144.4	138.7	133.0
2002	150.9	145.6	140.3	135.0
2003	151.7	146.8	141.9	137.1
2004	152.5	148.0	143.6	139.1
2005	153.3	149.3	145.2	141.1