SOUTH ASIA REGIONAL ENERGY STUDIES SERIES

SARESS

Review of Financial Restructuring Plan of Nepal Electricity Authority (NEA)

Prepared by AF-MERCADOS EMI
May 2012

THE WORLD BANK

ESMAP
Energy Sector Management Assistance Program

ASTAE

TABLE OF CONTENT

I BACKGROUND AND CONTEXT

The Nepal Electricity Corporation (NEC) was formed in 1962 with limited functions of operation and maintenance of Power Plants and consumer services. At the time of establishment, NEC had installed capacity just over 100 MW and a small consumer base. The Nepalese Electricity market was under state monopoly till 1984, being exercised through the Electricity Department (ED) of GoN, Nepal Electricity Corporation (NEC) and different special purpose development committees to construct hydroelectric projects. Planning and some development works were taken up by ED and major development works were taken up by specific development committees whereas operation and maintenance of the generation, transmission and distribution and supply businesses were taken up by the NEC.

The Nepal Electricity Authority (NEA) was established in 1985 under the Nepal Electricity Authority Act 1984 to meet the objective of creating a single entity responsible for planning, development as well as O&M, operating in a commercial manner.

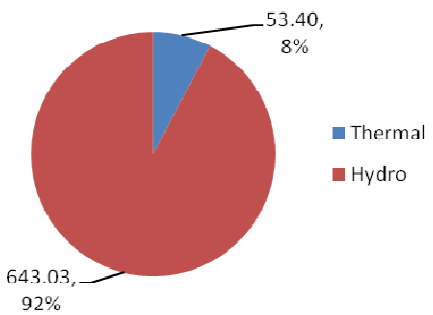
Table 1.1: Snapshot of NEA Progress since Inception[1]

Parameter	NEA at Inception ('erstwhile NEC')	NEA Today (July 2011)
Installed Capacity (MW)	103	~700
Consumer Base (Nos.)	1, 84, 000	20, 53, 000
Asset Base (NRS Billion)	2.73	109
Revenue Base (NRS Billion)	0.38	18.00

Source: NEA (2011)

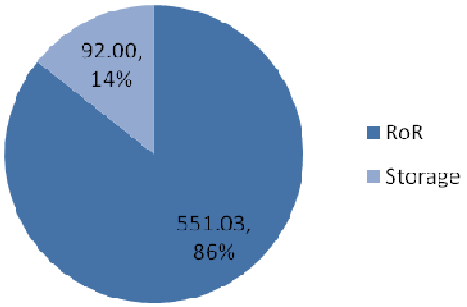
Currently the total installed capacity of the country is 700.9 MW as of 2009-10 of which 696.43 MW is within-grid power and ~5 MW of power being produced off grid. Figures 1.1 & 1.2 indicate the break-up of the capacity into hydro and thermal and also the type of HEP (as of 31st March 2011).

Figure 1.1: In Grid Capacity (696 MW)



Source: NEA (2011)

Figure 1.2: Hydro Capacity break-up (643 MW)



Over the years, the Nepalese Power Sector has witnessed significant interest from the multilateral funding agencies like the World Bank, Asian Development Bank (ADB), DANIDA, USAID, NORAD etc. with active investments in projects, programs and initiatives aimed at improving the Power Sector of the country.

The World Bank in particular has been making significant efforts to facilitate project development in the country by financing critical projects. Some of the investment in this regard include: (i) Rehabilitation of the Kali Gandaki 'A' Hydro Electric Plant (HEP), the largest plant in Nepal's power system, as well as two existing thermal plants in Duhabi and Hetauda; (ii) Financing of the Bharatpur-Bardaghat transmission line, to strengthen the old and severely overloaded distribution network in Kathmandu Valley, and expand the Government's off-grid micro-hydro rural electrification program; and (iii) Kabeli Transmission Project to support the addition of transmission capacity to the Integrated Nepal Power System. In addition to the above, several discussions are already underway to expand this portfolio further. However, several concerns exist.

[1] NEA has demonstrated technical capacity to implement and maintain transmission lines of up to 132 kV. The Integrated National Power System (INPS) has more than 1,600 km of transmission lines at the 132 kV level which are owned and maintained by NEA. In addition, INPS has about 370 km of transmission lines at the 66 kV level. Existing substation capacities are about 1415 MVA.

The Nepal Electricity Authority (NEA), the key body governing the power sector in Nepal has been under severe financial strain since the last 5 years and its ability to pay is a cause of concern that may affect many of the upcoming projects going forward. . The ongoing power crisis in Nepal has been hampering Nepal's economic development with over 14 hours power cuts in the lean hydro seasons.

The recent growth in generation capacity has been unable to keep pace with the demand and the country faces widespread outages, particularly in the lean hydro seasons. NEA serves 15-20 percent of the total population of Nepal which shows a relatively low level of electrification. There is a great disparity between urban and rural electrification rates as in urban area the rate is 90 percent where as that in rural area is 5-10 percent only.

Even though the electrification level is poor, it is expanding, placing burdens on the NEA operations and finances. NEA has not had the benefit of any tariff increases in the past ten years even though the cost of service delivery has gone up substantially. This has put NEA under severe financial strain. The position of power sector in Nepal is unsatisfactory because of low tariffs, high system losses, high generation costs, high overheads, over staffing, which has resulted in NEA suffering from excessive debt accumulation and lack of funds for undertaking expansion projects. The cost of generation and distribution of one unit of electricity has doubled in last ten years. This has led to accumulation of enormous amounts of liabilities for NEA and as a result of this, NEA has reached the brink of sustainability and is not able to perform its operations or reduce its AT&C losses.

The utility also faces high currency conversion risk since many generation projects are undertaken by NEA along with developers of foreign origin. This has led to transactions taking place in foreign currency, and since the Nepalese Rupees is steadily losing value, NEA has to pay more to transact in the foreign currency leading to massive losses.

In summary, key factors responsible for the weakening financial position of NEA are:

- No tariff revisions in the last 10 years
- High system losses
- Increasing Costs i.e. the Power Purchase Costs and O&M expenses
- Mismatch between the cost of supply and the revenue

Taking note of the above situation, NEA has embarked upon a path to arrest the current losses by developing a Financial Restructuring Plan (FRP) for the company[2]. The FRP covers several aspects such as issuing debentures, reducing financing costs, settling disputes, adjusting sales tariffs to match debt service requirements, etc.

However, there are several aspects that need to be additionally incorporated to ensure that NEA not only recovers from the current conundrum but is also able to effectively perform in view of the future changes being witnessed in the Nepalese Power Sector[3]. Keeping this in AF-Mercados EMI was entrusted to prepare a report that brings to picture these aspects along with their implications in the long run.

The report covers the following critical sections.

Section II- Analysis of NEA's Historical Performance

Section III- Need for a Financial Recovery Plan

Section IV- Emerging Issues and its Impacts

Section V- Annexures

---

[2] It is understood that the FRP prepared by the NEA has been discussed with the Nepalese Government and principally approved

[3] These changes are discussed and elaborated in the subsequent sections of the report

II ANALYSIS OF NEA'S HISTORICAL PERFORMANCE

The ongoing power crisis in Nepal has its roots in various inefficient practices that had been continuing since long. Over the years NEA has been under severe financial strain. Factors like irrational tariffs, high system losses, high cost of power purchase etc. have hampered Nepal's economic development with over 14 hours power cuts in the lean hydro seasons.

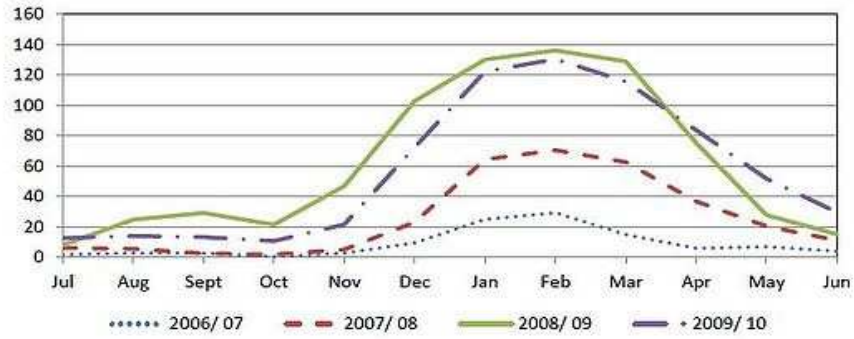
2.1 OPERATIONAL PERFORMANCE

The operational inefficiency of power sector in Nepal has played a major role in shaping up the current picture, where NEA is at a critical stage looking for serious changes. These inefficiencies have resulted in general shortage of electricity which is manifesting itself in scheduled power cuts which became an incremental part of power supply in Nepal within the last years. **Especially during dry-season Nepal's dependence on hydropower becomes obvious, forcing the NEA to cut power in Kathmandu up to 16 hours per day** (as in April 2011).

2.1.1 Demand and Supply Gap

The gap between demand and supply of power in Nepal is historical and is increasing year on year on account inadequate capacity addition and high level system losses. Figure 2.1 illustrates the growing gap between electricity demand and supply and corresponds with the appearance of load-shedding. Since 2006/07 the supply gap increased from 105 GWh to 678 GWh in 2009/10, with the temporary peak in 2008/09 with 745 GWh. Furthermore, the figure shows the seasonal fluctuations due to irregular run-off the river discharges. Due to glacier melt and intensive rainfall during the monsoon season, electricity supply almost matches the demand between June and October. However, during the winter (where precipitation is far less) generation capacity decreases along with diminishing run-off rivers.

Figure 2.1: Gap between Electricity Demand and Supply in GWh

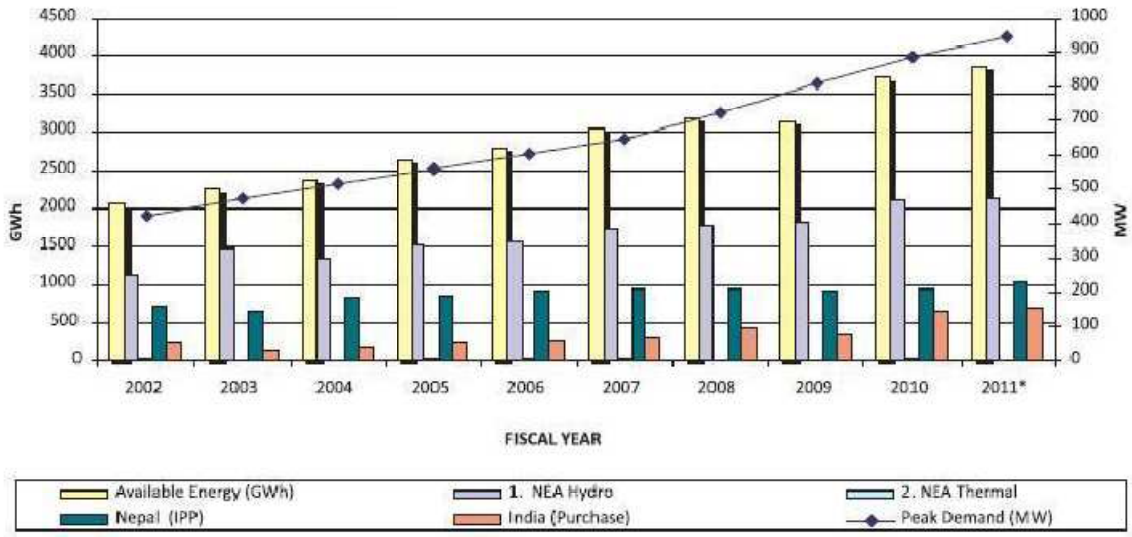


Source: www.energypedia.org

In order to meet the growing hunger for more electricity, imports from India became more important during the last decade. Whereas private and state-owned hydropower generation has doubled in the last ten years, power imports from India almost tripled (from 238 GWh in 2001 to 694 GWh in 2011). In 2008/09 consumption of electricity was almost balanced between industrial (manufacturing) sector (37.37 %) and households (45.52 %), while the commercial sector consumed only 6.6 %[20]. However, the industrialized and urban areas account for the majority of electricity demand. Around 28 % of electricity produced in Nepal in the year 2005 was consumed in the Kathmandu Valley alone.

Between 2002 and 2011 (estimated figures) peak demand has more than doubled from 426 to 946 MW. The shortage in electricity in Nepal has reached to a level ~ 500 MW in dry seasons. **This if not addressed, will jeopardise the sector in future.** Figure 2.2 shows the increasing trend in energy availability and peak demand

Figure 2.2: Total energy availability and peak demand

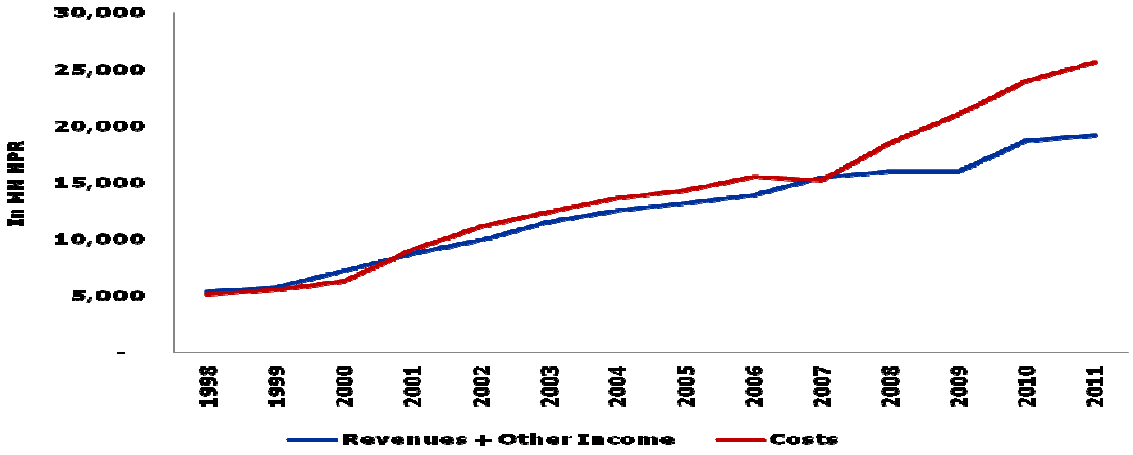


2.1.2 Tariff and Average Cost of Supply

The Nepalese power sector has been facing cash flow issues since more than a decade. The average cost of supply is far more than the revenue realized. The main factors responsible for this mismatch are non- adjustment of the electricity tariffs and increasing fuel and operating expenses. **In Nepal, tariff has been revised only twice in 1998 and 2001. The Electricity tariff was increased by 10% in September 2001. Since then there has been no tariff adjustment.**

Figure 2.3 compares the historical revenue and cost of supply of power, with implications that the average cost of supply has been higher than the revenue collected over most of time in last one decade.

Figure 2.3: Revenues Vs Costs

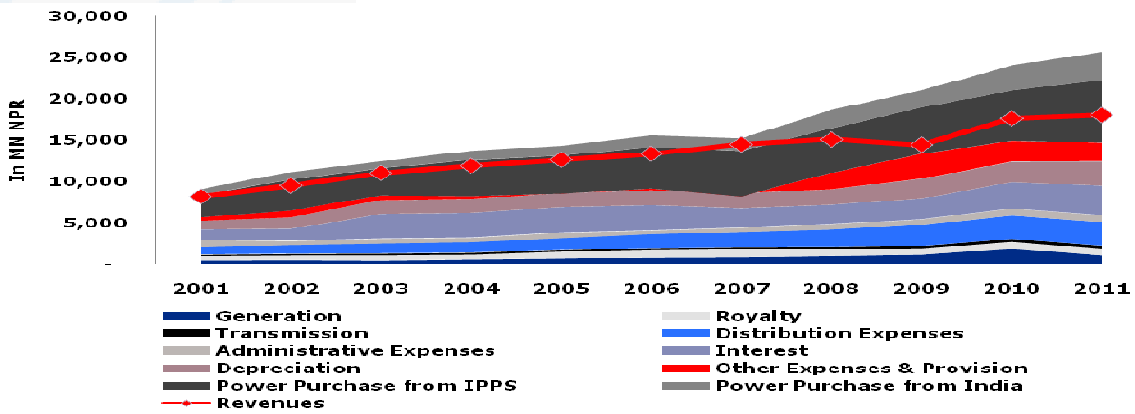


Source: NEA

The above situation is due to the fact that prices of all inputs in market have gone up many folds. About 45% of the total energy served by NEA comes through purchases. There is regular annual escalation of about 6% on most of the internal purchases from IPPs, about 5.5% on import under power exchange agreement and the import under trading agreements escalates by about 50%. NEA has been absorbing all these escalations over the years. Figure 3.2 shows the breakdown of cost of supply over the years. It is seen that historically the power purchase cost contribute almost 40% of the total cost of supply. The sudden increase in the cost of power purchase in 2007 had drastically increased the gap between revenues and total cost of supply. This gap has now reached abnormal levels.

As shown in figure 2.4 cost of power purchase contributes almost 40% of the total cost of power supply. There has been a tremendous jump in the cost of power purchase post 2007. Since then the expenses have drastically increased, however the revenues have not been able to keep pace with it.

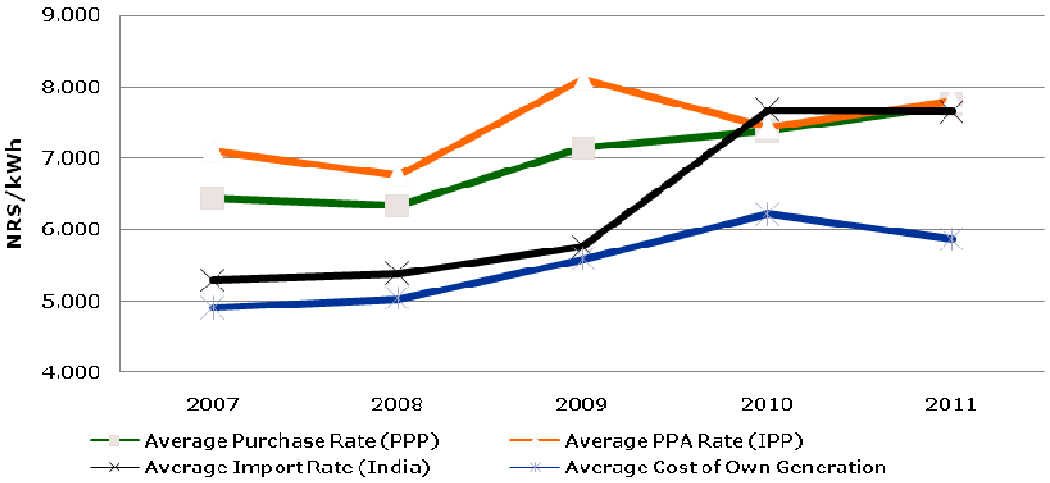
Figure 2.4: Breakdown of Costs over the Years



Source: NEA

Another analysis shown in figure 2.5 based on historical data reveals that the cost of power purchase especially that of imported power India has been hitting the finances of NEA the most**.**

Figure 2.5: Variations in the total Generation Costs in NRS/kWh (Own Generation and Power Purchase costs)



Source: NEA

If we analyze the average sales price and cost of service in Nepal since 2006-07, the cost of service per unit has increased at CAGR of 8.74%, while the average sales price per unit has increased at a minimal CAGR of 0.08%. Table 2.1 compares the sales and cost figures from 2006-11.

Table 2.1: Average Sales Prices Vs Cost of Production from 2006-2011

Description	FY 2006/07	FY 2007/08	FY2008/09	FY2009/10	FY2010/11 (Provisional)
Avg. Sales Price (NRS per kWh)	6.56	6.51	6.46	6.63	6.58
Cost Of Service (NRS per kWh)	6.91	7.33	9.17	9.77	9.66
Net Profit (Loss) (NRS per kWh)	(0.35)	(0.82)	(2.71)	(3.14)	(3.08)

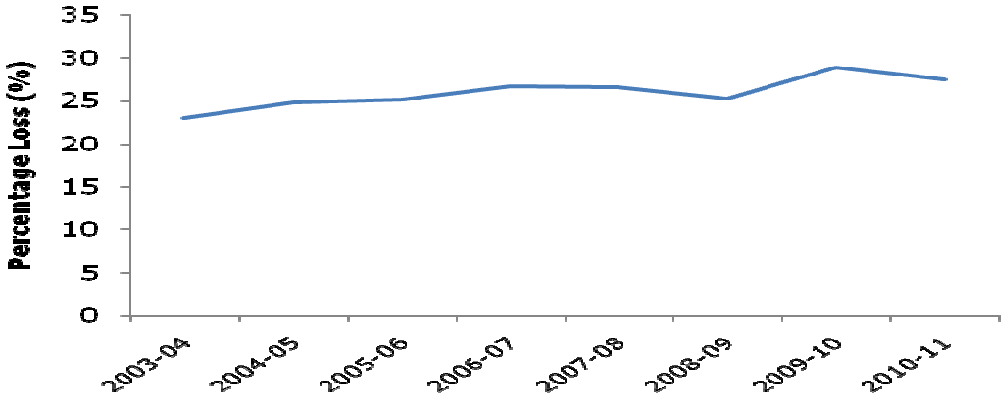
Source: NEA

2.1.3 Technical and Commercial losses

It is widely accepted that NEA's non-technical losses are excessive, and that any initiative to reduce losses must target those losses as first priority. Various initiatives in this regard were taken, however all in vain. **Some of them include the inclusion of targets for loss reduction in management contracts for the distribution centers; and a scheme, supported by the Danish Government, to sell electricity at discounted wholesale rates to consumer co-operatives, which assumed ownership of the local distribution networks and responsibility for their operation. NEA committed to decrease losses by 2% every year; however this could not be realized.**

The Government also introduced the Electricity Theft Control Act 2058 and the Electricity Theft Control Regulations 2059, which treated electricity theft as a criminal offence and gave NEA new powers to deal with the problem. However no significant improvement could be achieved and slowly these losses started showing their impact on the finances of NEA. **In 2003 the system losses were 22.9% which have now reached to level of 27.4% in 2011.** Figure 2.6 shows that despite several initiatives, the losses in NEA's system have gradually increased.

Figure 2.6: NEA's System Losses over the Years



Source: NEA

2.1.4 Project implementation

NEA has been facing high cost of projects constructed under grants as these projects are awarded under limited bidding (i.e. MMHEP). NEA has also been facing delays in project development. **The 10th five year plan had set a target of adding 314 MW of power (100MW by NEA and 214 by private sector) only 40 MW could be added.**

The MMHEP (70MW) was delayed by 5 years and its cost was just double than the base price of estimated amount.

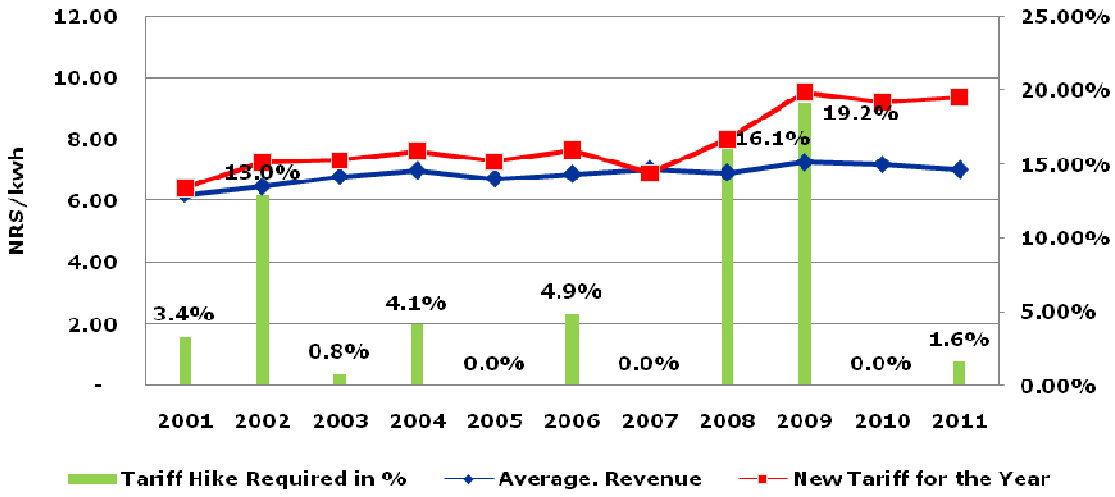
The construction of the KL-III, Chamaliyagarh and Trishuli-IIIA projects has been delayed. The construction of UTKHEP is also getting delayed and revised target for completion is 2015

Due to delays in construction of the 220KV transmission lines especially Hetauda- Bardaghat , transmission system has encountered congestion and is unable to transfer all the powers generated by KG A and MMHEP to Kathmandu-Hetauda- Biratnagar. This has resulted in spill energy in wet season on one hand while on the other; NEA has to resort to load shedding even in wet season.

2.1.5 NEA's historical performance with key measures incorporated

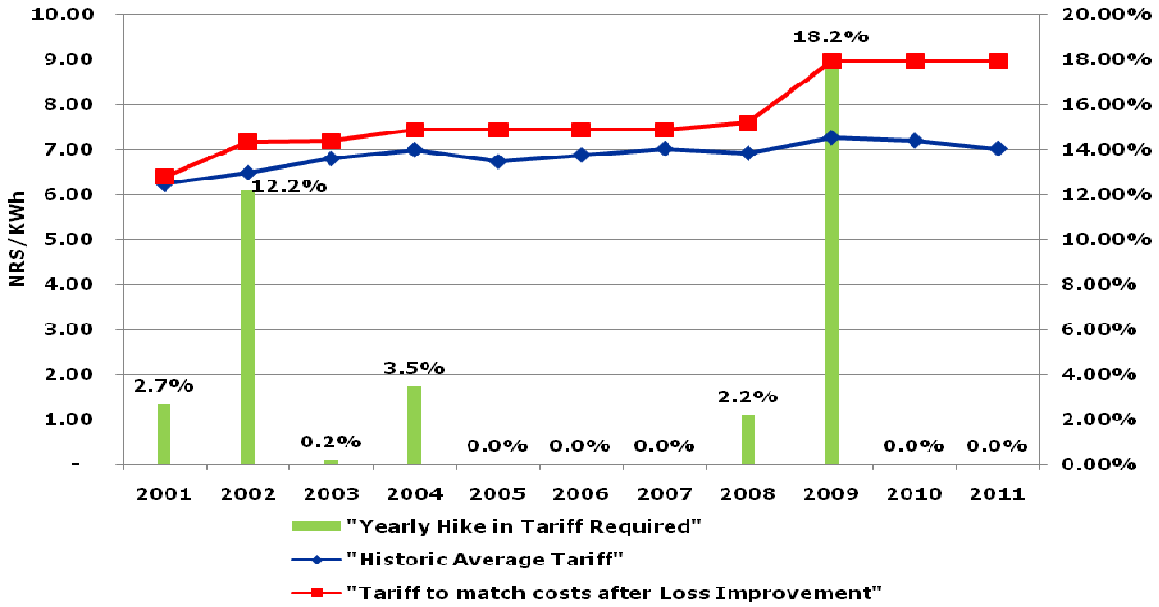
AF-Mercados analysed NEA's historical performance incorporating certain key measures. Figure 2.7 shows the annual tariff hike that would have been required to match revenues costs. Similarly if there would have been a loss reduction of 0.5% annually the required tariff hike would have been lower as shown in figure 2.8.

Figure 2.7: Tariff Hikes in each year to bridge revenue gap (over last 10 years)



Source: NEA

Figure 2.8: Tariff Hikes in each year to bridge revenue gap (over last 10 years) @ 0.5% loss reduction each year



Source: NEA

2.1.6 Demographical and Geographical issues

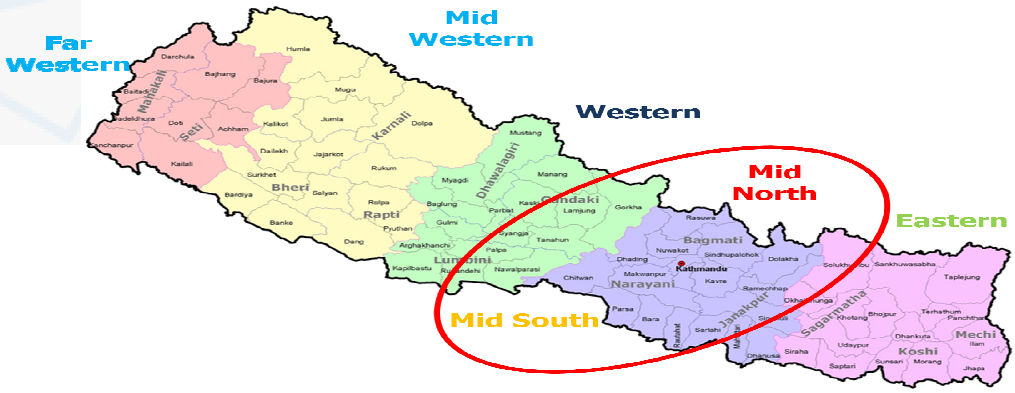
The geographical condition of Nepal does not allow grid extension to remote rural areas due to high infrastructure cost and losses, lack of optimum load, and poor returns compounded by constrained Government budget. Against the backdrop, modern energy solutions in the form of improved cook stoves, biogas, and agriculture and forest waste based biomass power generation plants, distributed generation, there is a great disparity in the electrification rate in Nepal, and in the urban areas it is 90 percent where as in rural areas it is less than 10 percent only.

Nepal has significant rural population (approximately 80%[4] of total population with over 30% living below the poverty line of US$ 12 per person /per month) including large segments that still do not

[4] Source: International Fund for Agricultural Development, 2004

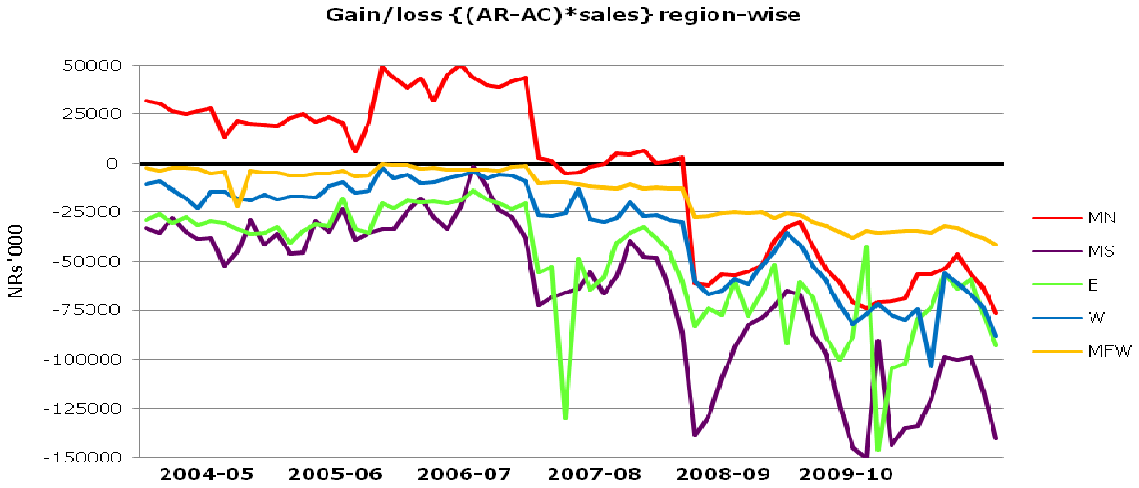
have access to electricity. Lack of adequate access or increase in electricity prices significantly impact their standard of living and is generally accompanied by corresponding reduction in spending on basic amenities. Inadequate supply of electricity further accentuates inequality in the Nepalese society.

Figure 2.9: Nepal's Urban and Rural Geographies



Except for the Central Region (Mid North and Mid South), a large part in the country is predominantly rural in the country. Based on the analysis it is seen that the cost of serving rural areas in Nepal has been too high. Rural areas hardly contribute in the overall revenue and since 2007 there has been significant loss in such supplies. Figure 2.10 shows the same

Figure 2.10: Cost of serving rural areas



Source: NEA

2.2 FINANCIAL PERFORMANCE

Due to continuous financial loss in the last few years NEA's financial health is in bad shape. Various factors have contributed in deteriorating NEA's financial health in last few years. **Not only the pending tariff adjustment for a long period, but also the higher cost of capital, high cost of granted as well as bilateral projects, rural electrification and high power purchase agreements costs in past have been the reasons for worsening financial performance of NEA**. It is also noted that high cost of service along with no tariff adjustment for almost a decade has not only weakened NEA's financial health, it is also contributing towards miss match between demand and supply in electricity market resulting into very serious economic problem called upon by long hours of load shedding in Nepal.

NEA has not been able to generate sufficient cash from business operation, which is required for debt service obligation and for funding future development projects (generation, transmission, distribution and strengthening). There has been year on year increase in payable to government and such outstanding payable was recorded to Rs 21.02 billion in FY 2009/10. Net losses for the FY 2009/10 were recorded to Rs 6.96 billion compared to Rs 4.9 billion losses in FY 2008/09. This has weakened NEA's ability to pay current liabilities (payment to contractor) on time. Table 2.2 presents a snapshot of NEA's financial status for the last five years.

Table 2.2: Financial Snapshot of NEA

Figures in Million NRS

Description	2006	2007	2008	2009	2010	2011
Revenues	13,332	14,450	15,041	14,406	17,165	18,004
EBITDA	3,516	4,118	3,651	2,846	1,997	2,283
PAT	(1,268)	240	(2,315)	(5,093)	(6,924)	(6,512)
Shareholder's Equity	17,568	20,730	21,032	21,058	19,261	16,100
Change	-	3,162	302	26	(1,798)	(3,161)

Source: NEA (2011)

Table 2.2 clearly shows the grim picture of NEA's finances over the years**. NEA has been suffering from a negative operating margin and underinvestment. Excess demand has lead to widespread power rationing.**

2.2.1 Operational Costs

The weak financial position of NEA is on account of increasing expenses in terms high operational costs. NEA purchases power at a very high rate. **As of 2009/10, the effective power purchase rate from IPPs and Import is higher (NRS 8.97 / KWh) than NEA's average net sale price (at NRS. 6.58 /KWh). Thus, NEA incurs a direct loss of NRS 2.25 per unit on sale of every kWh.** This is further contributing to the already high financial losses incurred by the NEA. PPAs are on "Take or Pay" basis. Thus even during wet season, NEA is compelled to buy energy from IPPs and spill the water from its generators. During dry season, NEA has to import power from India on commercial terms to meet the energy demand.

Among the IPPs with the higher purchase rates, Himal Power Company (HPLC) is the most expensive followed by Bhotekoshi Power Company (BKPC), Chilime Hydropower Company Limited (CHPCL) and Butwal Power Company (BPC). PPAs in the first two cases are dollar denominated resulting in the exchange risk as well. Table 2.3 indicates the contract energy and average rate from various IPPs for 2009/10. a large part of the cost remains unrecovered. The revenue gap was of the order of NRS 3.08 per unit at the end of FY 2010/11

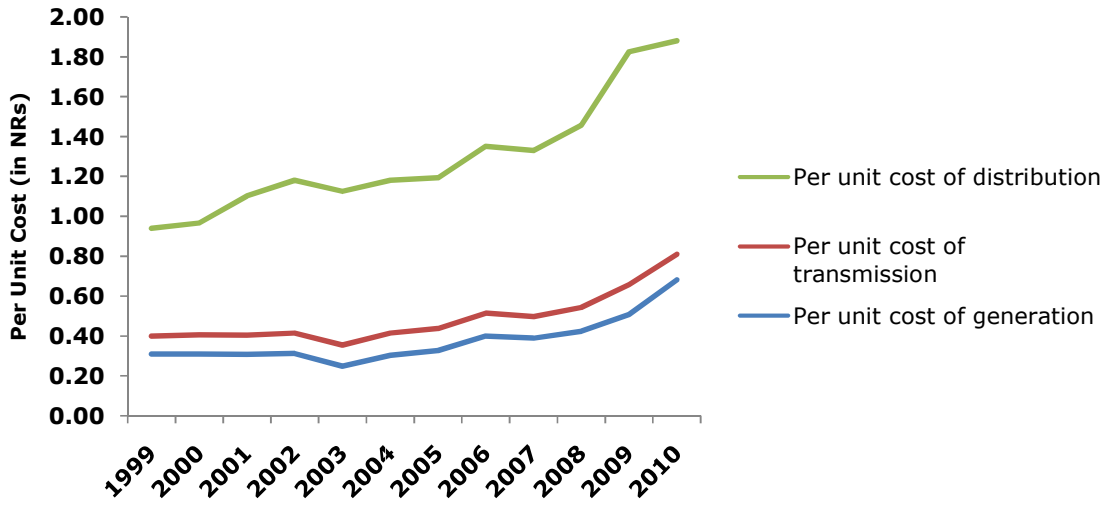
Table 2.3: Average Tariffs & Contract Energy for IPPs during 2009/2010

Plant	Average Rate (NRS /kWh)	Contract Energy (GWh)
HPLC	6.97	350
BKPC	6.84	246
CHPCL	6.27	133
BPC	5.17	850

Source: NEA (2011)

Besides power purchase costs, the cost of NEA's own generation, transmission and distribution have increased drastically in last 5 years. Figure 2.11 below shows the historical trend of per unit cost contribution by generation, transmission and distribution segments in Nepal. There has been a significant increase in the costs particularly generation.

Figure 2.11: Historical Trend of Per Unit Cost Contribution by Generation, Transmission and Distribution Segments in Nepal



A look at the operating expenses of NEA in 2008-09 and 2009-10, clearly indicates that power purchase costs and generation costs are the primary components of operating costs and have been contributing maximum share in the overall increase of costs. Table 4.2 compares the operating costs and the % increase in different components.

Table 2.4: Operating Expenses in 2008-09 and 2009-10

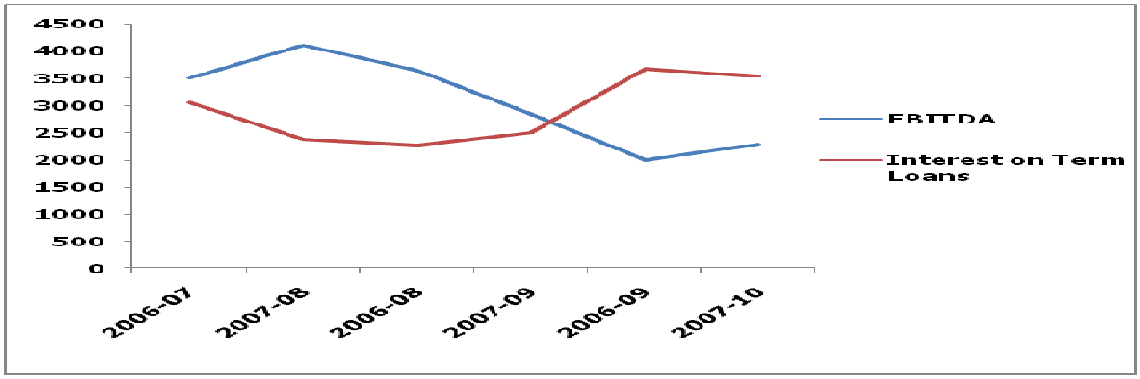
Operating Expenses (M. NRs)			
	2008-09	**2009-10**	**% Increase**
Generation	1119.7	1541.26	37.6
Power Purchase	7691.2	9746.5	26.7
Transmission	328	337.7	3.0
Distribution	2575.09	3091.2	20.0
Others	3,905.58	4,653.50	19.2

Source: NEA

2.2.2 Financing costs

NEA has been facing high cost of projects constructed under grants as these projects are awarded under limited bidding (i.e. MMHEP). High interest rates have been impacting the cash flows of the NEA. Interest rate on long term loan under bilateral and multilateral agreement is 8% (up to 2005/06 it was 10.25%). The interest on term loan has been increasing year on year and resulting in negative profits. Figure 2.12 shows the increasing interest burden of NEA.

Figure 2.12: Year on Year comparison between EBITDA and Interest on Long Term Loans



Source: NEA

There is net outstanding amount of 50.4 Billion for the projects having high interest rates i.e. 8%.

Considering the low foreign exchange risk to GON present relending rate is still high to NEA. Further it has been difficult for NEA to mobilize resources from internal source for capital investment in new projects due to increasing operational loss resulting annual cash deficit.

Investment in Renewable Energy in Rural Areas by NEA is also a loss making business. Grant assistance by WB, ADB to GON is also transferred to NEA as loan. Rate of return on RE investment is very nominal, consequently, NEA can't sustain in long run.

2.2.3 Other Financial Issues

There are several other issues which have affected NEA's finances in recent years. Some of them are:

- Electricity act 1992 provides for royalty on the sales price of electricity at generation point. The IPPs have been paying on the same basis. **However NEA has been paying royalty at the selling price assumed at generation point Rs. 5.41 per kWh which is higher than the actual deemed selling price at the NEA's generation station (Rs 4.0 per kWh) even after adding 12% profit margin in its actual cost of generation Rs. 3.57. This has added the expenditure by Rs. 150 million per annum to NEA**. Recently MoLD (Ministry of Local development) has demanded royalty from NEA on the power purchase from Tanakpur which is not justifiable

- The receivables from municipalities on account of street lighting amounted to NRS. 1.84 billion up to 2008/09 and the Government of Nepal (GoN) paid NRS. 980 million and the balance of NRS860 million was written off by NEA. The payment mechanism for the street light bill of Municipalities' from FY 2009/10 as well as outstanding bill of VDC has not been finalized and the total receivable stood approx. at NRS. 2,253.50 million up to 2010/11 including 25% surcharge

- In the last five years, NEA's power stations generated only 2,093.23GWh which is less than by 21% of the annual generation of 2647.55 GWh. NEA is losing an annual income of Rs 2,650 million from the potential sale of 554.32 GWh.

- At present NEA's liabilities towards retiring employees' amount to about Rs. 9,000 million as per actuarial valuation but NEA does not have fund to manage this liability. Many claims put forward by the contractors are in the process of tribunal. If these claims are not settled in NEA's favor, then NEA will have to bear additional liability of NRs. 8/10 billion.

2.2.4 Financial Position of NEA

Since there has been no adjustment in electricity sales tariff since 2001 the financial health of NEA has aggravated. **Deficit budget stands at about NRs. 6,000 million p.a**. **Annual financial loss of NEA is increasing about by Rs. 7 billion million every year. The financial position as in 2010 was as follows:**

- **Share Capital-** Rs 38.64 billion
- **Reserve & Surplus-** Rs (18.42) billion
- **Long Term Loan-** Rs 58.02 billion
- **Net Working capital-** Rs (25.66) billion
- **Net Fixed Assets-** Rs 83.13 Billion
- **Capital Work in Progress**- Rs.16.90 billion
- **Investment in Equity Shares-** Rs 4.42 billion
- **Net loss for the FY 2009/10-** Rs 5.95 billion
- **Deficit Cash Flow-** Rs. 7.81 billion
- **Overdue payable to GoN**
  - Interest: Rs.14.91 billion
  - IDC : Rs. 10.16 billion,
  - Royalty : Rs. 1.06 billion

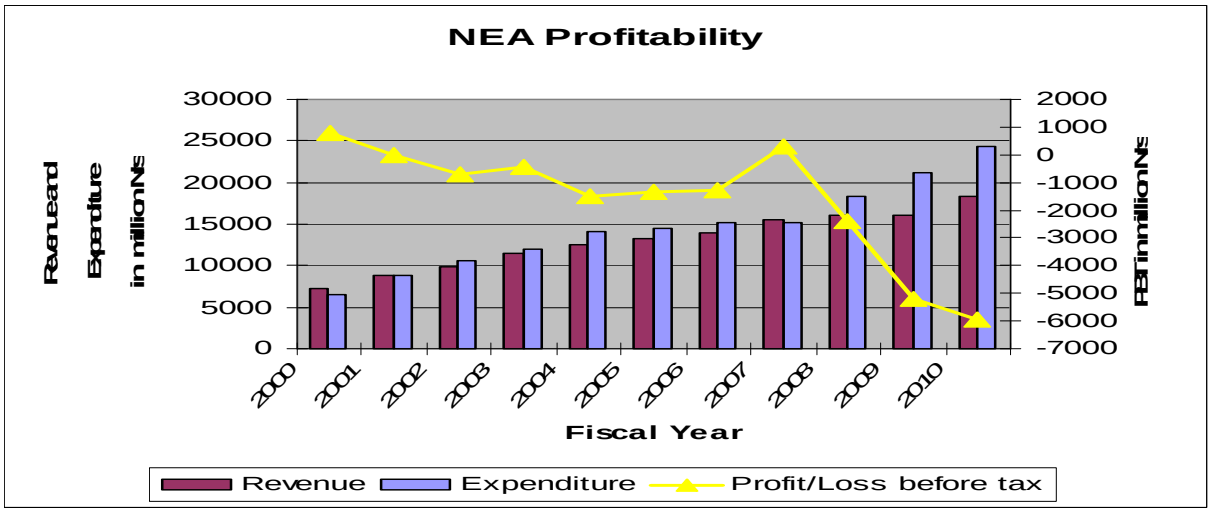
Currently the accumulated financial loss stand at Rs. 27.53 billion (provisional) and has crossed 2/3 of its paid up capital. The profitability status of NEA has been shown in Table 2.5

Table 2.5: Profitability Status of NEA

Description	FY 2006/07	FY 2007/08	FY2008/09	FY2009/10	FY20010/11(pro.)
Net income from sale of electricity	14,449.93	15,041.49	14,405.93	17,164.60	17,934.18
Total Expenses	16,020.69	(18,311.62)	(21,120.82)	(25,276.46)	(25,635.40
Operating Profit (loss)	(1,570.76)	(3,2270.15)	(6,714.89)	(8,111.86)	(7,701.22)
Other Income	1,016.61	(934.66)	(1,601.67)	(1,188.27)	1,189.58
Net profit (Loss)	(554.15)	(2,335.47)	(5,113.22)	(6,923.59)	(6,511.64)
Accumulated Loss	**6,650.14**	**8,985.61**	**14,098.83**	**21,022.42**	**27,534.06**

Source: NEA

Figure 2.13: Graphical Representation of NEA's Profitability



Source: NEA

If tariff is not increased within this fiscal year then the accumulated loss would be about NRs. 50,000 million in the next 3 years. This will make the net worth negative. Consequently NEA will be unable to meet the cost of operation, maintenance, and power purchase

The historical trend of NEA's financial ratios given in table 2.6, clearly indicates the cash flow crisis in the sector.

Table 2.6: Ratio Analysis of NEA's Historical Performance

Description	FY 2006/07	FY 2007/08	FY 2008/09	FY 2009/10	FY 2010/11 (pro.)
Solvency ratio	30:70	30:70	28:72	25:75	21:79
Gross profit Ratio (%)	37.48	36.64	31.03	27.32	26.57
Expense Ratio (%)	105.36	113.98	146.47	147.96	142.94
Net profit Ratio (%)	1.67	(6.39)	(31.82)	(37.72)	(34.05)
Return on Fixed Assets (%)	5.07	2.53	(3.90)	(3.96)	(3.52)
Debt Service Coverage Ratio (%)	1.32	1.25	0.40	0.33	0.38

- **The decreasing solvency ratio over the years is an indication that NEA has been aggressively using debts to finance its assets. This is also on account of accumulating interest payments.**
- **There has been a regular decline in NEA's gross profit margin. This is on account increasing costs and inadequate revenue realization.**
- **On account of increasing cost of power purchase and other operating costs there has been a drastic increment in the expense ratio of NEA over the years.**
- **Since 2007-08 NEA has been suffering from a negative net profit ratio. This is on account of a negative operating margin that has continued over the years**
- **The increasing debt burden and inadequate revenue has completely degraded NEA's DSCR. There is hardly any cash flow available to meet annual interest and principal payments on debt, including sinking fund payments**.

III NEED FOR A FINANCIAL RECOVERY PLAN

The historical analysis in the preceding section shows that NEA's operational and financial health has been under serious threat over the years. Looking at the current status of NEA it seems that unless urgent measures are taken, the sector will see serious consequences in the future.

3.1 CURRENT STATUS OF NEA

Currently the peak load in the country is ~947 MW resulting in a shortage of over 500 MW in dry seasons. Out of total installed capacity of ~700 MW, only 308 MW was available during the winter of 2009-10. **Even with a maximum available import capacity of 80 MW, a deficit of over 50% of demand was inevitable. The peak and energy demand is growing at an average annual rate of about 10%.** Shortage of energy and capacity is expected to continue for quite some time to come as there is no significant addition of generating plants. The shortage has forced NEA to resort to load shedding.

Table 3.1 shows the volatility of the power supply during the wet and dry seasons. The Nepalese Power Sector faces a peak shortage of ~450 MW.

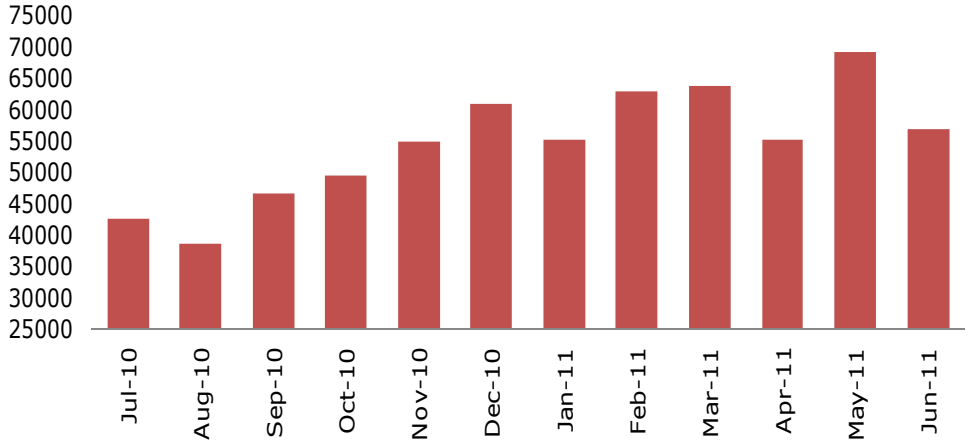
Table 3.1: Variability in Power Supply & Demand during Wet and Dry Seasons.

Season	Demand (MW)	Availability (MW)	Surplus (MW)
Wet Season	1185	1286	101
Dry Maximum	1292	833	-459

Source: NEA (2011)

At the consumer end, shortage of power in the lean hydro seasons has led to increased deployment of coping strategies, particularly in the use of diesel to substitute non-availability of the grid power. This can be clearly witnessed from the increased diesel consumption by consumers in Nepal during the lean hydro season i.e. from December to May 2011 (Refer Figure 3.1). Future projections indicate that the shortage scenario particularly during the dry season is likely to continue in the next five years (2014-15).

Figure 3.1: Month-wise break of Diesel Consumption (in kilo litres) during 2010/11

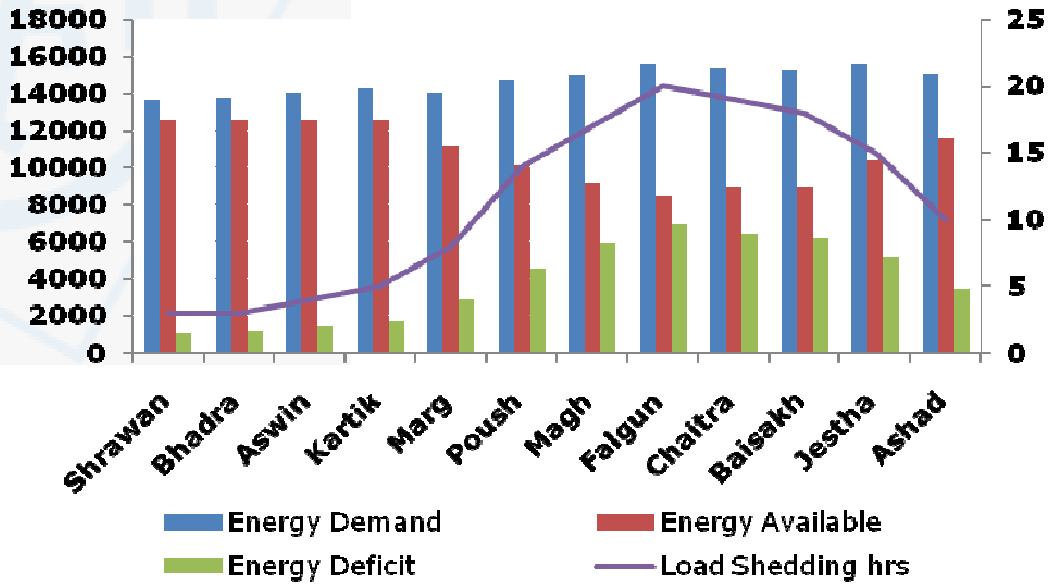


Source: NEA (2011)

NEA system load curve has peak demand in the evening (usually between 5:30-9:30 PM) followed by another peak in the morning which is about 80% of the evening peak. Peak happens in winter season when the discharge in the rivers decreases. Nepal experiences critical power shortages during winter period.

Figure 3.2 below shows the energy demand/ supply and the corresponding load shedding in 2011-12. It is seen that the months of Falgun and Chaitra witnessed maximum energy deficit with load shedding reaching almost 19-20 hrs daily.

Figure 3.2: Demand/ Supply and Load shedding Scenario in 2011-12



Source: NEA

In Nepal the increased demand for power is growing at a rate of over 9% YoY: The energy requirement projected for FY 2016-17 is over 7600 MUs. **The upcoming Muzaffarpur – Dhalkebar 400 kV line is likely to create significant demand pressure within Nepal as it allows higher capacity of electricity transmission as compared to its existing lines of ~100kV**. The demand is likely to match up with the energy requirement (or the unconstrained demand).

The increasing demand is placing burdens on the NEA operations and finances. NEA has not had the benefit of any tariff increases in the past ten years even though the cost of service delivery has gone up substantially. This has put NEA under severe financial strain. **The position of power sector in Nepal is unsatisfactory because of low tariffs, high system losses, high generation costs, high overheads, over staffing, which has resulted in NEA suffering from excessive debt accumulation and lack of funds for undertaking expansion projects. The cost of generation and distribution of one unit of electricity has doubled in last ten years.** This has led to accumulation of enormous amounts of liabilities for NEA and as a result of this, NEA has reached the brink of sustainability and is not able to perform its operations or reduce its AT&C losses.

The utility also faces high currency conversion risk since many generation projects are undertaken by NEA along with developers of foreign origin. This has led to transactions taking place in foreign currency, and since the Nepalese Rupees is steadily losing value, NEA has to pay more to transact in the foreign currency leading to massive losses.

In summary, key factors responsible for the weakening financial position of NEA are:

- No tariff revisions in the last 10 years
- High system losses
- Increasing Costs i.e. the Power Purchase Costs and O&M expenses
- Mismatch between the cost of supply and the revenue

Taking note of the above situation, NEA embarked upon a path to arrest the current losses by developing a Financial Restructuring Plan (FRP) for the company[5]. The FRP was developed by a committee formed by the Government of Nepal. The FRP covers several aspects such as issuing debentures, reducing financing costs, settling disputes, adjusting sales tariffs to match debt service requirements, etc. Salient features of RFP have been discussed in the next chapter.

[5] It is understood that the FRP prepared by the NEA has been discussed with the Nepalese Government and principally approved

3.2 SALIENT FEATURES OF FINANCIAL RESTRUCTURING PLAN (FRP)

The Financial Restructuring Plan is aimed at bringing following changes:

- **To meet cost revenue gap**
- **To translate negative Balance Sheet into positive one.**
- **To promote the development of an efficient, reliable, commercially viable in power sector**
- **To reduce dependant on Government for support**
- **To finalize the SLA**
- **To settle the receivables & payables between GoN and NEA**
- **To adjust electricity sales tariff based on**
- **Cost (required to hike by 40% to meet BEP)**
- **Debt service (required to hike by 45% to meet DSCR)**
- **Cash flow for Project investment and recovery of accumulated losses within a period of four years (required to hike by 75% to meet project investment)**

The Plan will aim to incorporate following recommendations:

- **Financial Institutional Reform (Share Capital, Reserve & surplus)**
  - Increase Authorized capital From NRs. 30 billion to NRs 75 billion
  - Writing off accumulated loss NRs 27.53 billion
  - Conversion of Interest During the Construction Period (IDC) NRs. 9.620 billion into Equity
  - Revising the ratio for project investment between GoN and NEA from 5% and 15% to 10/10% .
  - Writing off Foreign Technical Assistance (TA) received other than Capital Goods instead of current practice of capitalizing in equity and/or Long Term loan

- **Long Term Loan & Grants**
  - In case of projects for which no subsidiary agreement has been made, such agreement has to be made without delay
  - Projects constructed funding through foreign grants shall be capitalized at 50% of such grants and the same shall be accounted as loan instead of grants
  - Grants related to the projects (**Middle Marsyangdi HEP and Load Dispatch Center extension)** shall be converted accordingly(SLA has not been concluded)-

- **Interest Rate**
  - Reducing interest Rate from 8% to 5% financing through foreign source.
  - Reducing Interest rate on local source from 6.5 % to 5%.
  - In case of the projects in which interest rate is specified but SLA has not entered into, SLA has to be made fixing the rate at 5%.
  - Interest rate of the project with specified interest rate less than annual 5% has to be maintained as it is.
  - For calculating IDC of a project, the interest rate shall be calculated by taking only 50% of the chargeable interest rate.
  - IDC of a project from a grant should be zero
  - The aforesaid interest rate should be made applicable from FY 2009/10

- **Electricity Royalty**
  - Royalty shall be calculated as per the provision of Electricity Act 1992 i.e on the basis of selling price at Generation point

- **Capitalization of the MMHEP**
  - Out of foreign portion of the grant Rs 13.540 billion, account only Rs. 6.670 billion i.e. 50% of the grant as loan while capitalizing the project. (GoN should give up 50%)
  - IDC and cost of the project increased from foreign exchange loss should also be adjusted accordingly. This will reduce the project cost by Rs. 4.75 million.

- **Settlement of Arrears between GoN and NEA**
  - GoN has to receive from NEA Rs.21,412.34 billion and NEA has to receive from GoN Rs. 5,208.46 billion.
  - To adjust these amounts, the net amount payable by NEA to GoN is Rs. 16,203.88 million

- **Payment mechanism of Street Light Bills**
  - GoN should deduct the amount of street light bill from the allocation of budget to local bodies and to make the full payment of such bill to NEA

- **Incorporation of Rural Electrification Company**
  - To mitigate the heavy loss suffering from rural electrification, a rural electrification company under the ownership of GoN should be incorporated.
  - The assets , liabilities based on rural electrification and the organizational structure of NEA have to be handed over to such company
  - **Alternatively**, GoN has to operate rural electrification program only by providing subsidy to NEA

- **Operation of Multi fuel and Diesel Plant**
  - If the multi fuel and diesel centers have to be continuously operated to supply electricity, the operation cost exceeding the average generation cost of NEA has to be made available to NEA by GoN as a subsidy
  - If the operation is only for the voltage improvement, NEA has to bear the entire cost

- **Issue of Debentures**
  - To manage the required fund for project investment, it would be appropriate to make provision of investment by issuing debentures against the security of GoN

- **To control Electricity Losses**
  - Reduce loss by 2% per year as committed in earlier years by NEA
  - GoN should co-operate for loss reduction
  - Initiate the activities specified in the Electricity Crisis Mitigation Program 2065 regarding loss control

- **Electricity Tariff adjustment**
  - Legal provision for tariff fixation is already made
  - The Electricity Tariff Fixation Commission should take appropriate decision with regard to the long awaited tariff adjustment

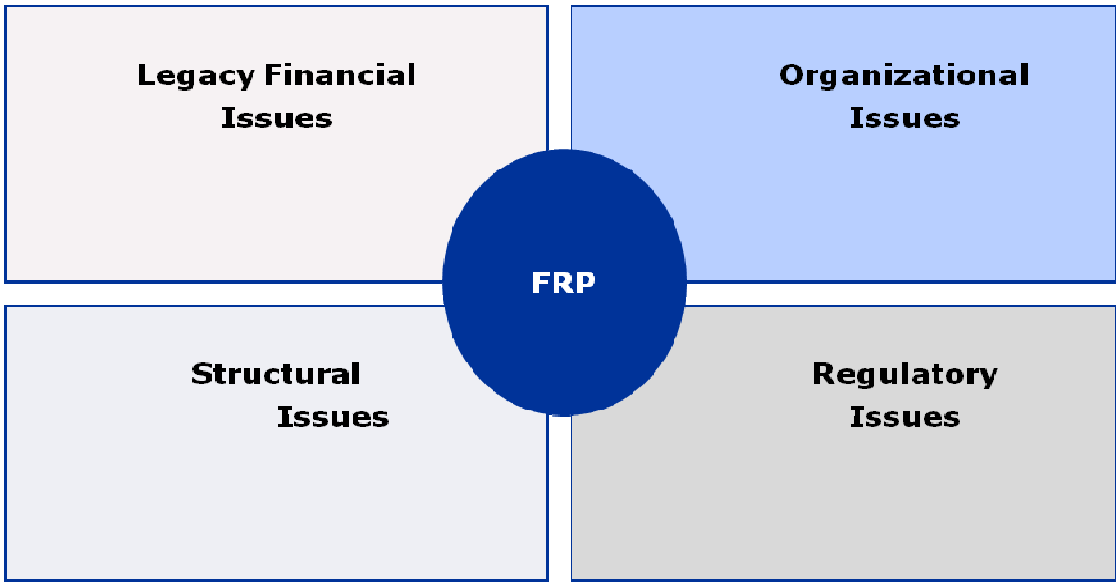
Though the Financial Restructuring Plan more or less covers all the aspects pertaining to NEA's financial health, its overall aim has to be to develop a plan that provides strategic direction to NEA so that it not only recovers from the current financial stress (aim of Financial Restructuring Plan) but also to provides recommendations to sustain this in the long-run.

Thinking on these lines AF-Mercados EMI proposes a Financial Recovery Plan**.** Unlike a Financial Restructuring Plan which is focussed on accounting issues, a financial Recovery Plan aim to analyze and incorporate several other dimension and not just financial and accounting issues. AF-Mercados EMI has analysed NEA's current position through following approach.

- Analysis of past performance and identifying critical issues affecting NEA's performance
- Identifying future development that could impact NEA finances significantly
- Looking at other dimensions that can contribute towards improvement of NEA's performance towards long run.

Hence the Financial Recovery Plan proposed as part of this report looks at the following aspects (Figure 3.3) to be addressed so that the overall reform measures are sustained in the long run.

Figure 3.3: Things FRP Should Address



1. **Legacy Financial Issues-**
   - Tariffs abnormally low due to absence of revision since last 10 years
   - Escalating and Volatile Costs – Power Purchase and Operational
   - Huge Capital Commitments resulting in Cash Flow Constraints for NEA
   - Large Energy Inflows with no commensurate tariff flexibility.

2. **Organizational Issues**
   - Unwieldy Organizational Structure – very large number of field accounting units (cost centres) resulting in lack of control and operations losses and leakages

3. **Structural Issues**
   - Outdated Systems and Procedures
   - Large number of employees – Over 10,000 employees with low professional to non-professional ratio

4. **Regulatory Issues**
   - Inability/unwillingness of NEA to expand and serve rural areas
   - No regulatory push towards rationalization of tariffs

A Comprehensive FRP besides addressing the above issues should also recognize the inter linkages and inter dependencies among the above issues and decide on appropriate course.

IV EMERGING ISSUES AND ITS IMPACT

The financial restructuring plan which aims at bringing reform on the financial and accounting front does not however consider other issues that might affect the future of power sector in Nepal. The analysis done by AF-Mercados EMI in the process of developing a financial recovery plan focuses on such developments in future. The anticipated scenario post restructuring is as follows:

- **The extent of financial restructuring requirements will be closely linked to the tariff awards**
- **One time financial restructuring necessary, but not sufficient in a volatile operating environment**
- **Next few years are likely to see significant changes:**
  - New Generation projects will come
  - Larger IPP participation
  - New Transmission Lines
  - Large Quantity of Power Flows in the System with high level of volatility in the system

There are several key challenges that need to be addressed as early as possible; otherwise the purpose of financial restructuring would be defeated. Some of these challenges are:

- **Tariffs abnormally low due to absence of revision since last 10 years**
- **Escalating and Volatile Costs – Power Purchase and Operational**
- **Huge Capital Commitments resulting in Cash Flow Constraints for NEA**
- **Large Energy Inflows with no commensurate tariff flexibility. Unless tariffs are made more flexible, NEA could potentially suffer financially**
- **Outdated Systems and Procedures**
- **Unwieldy Organizational Structure – very large number of field accounting units (cost centres) resulting in lack of control and operations losses and leakages**
- **Inability/unwillingness of NEA to expand and serve rural areas**
- **Large number of employees – Over 10,000 employees with low professional to non-professional ratio**

In order to study the impact of future developments in the sector, AF-Mercados EMI has done the following analysis:

- **Analysis of the demand trends witnessed by NEA;**
- **Supply of electricity from various sources and identification of demand and supply gap, duly considering time of day and seasonal aspects;**
- **Analysis of operations costs of NEA and trends in this regard;**
- **Assessment of tariffs and a comparison of the tariffs with average cost of service delivery**
- **Assessment of T&D losses and loss reduction based on available information**
- **Development of a detailed financial model consisting of operational. projections, investment plans, financing plans, tariff scenarios, etc**

In an attempt to foresee the sector scenario by the end of 2018, AF –Mercados EMI has been able to estimate revenues and costs under certain reform measures. Besides that impact of future developments in the sector on the financial and operational health of NEA has also been done. These have been discussed below.

- **Increased demand for power growing at a rate of over 9% YoY:** The energy requirement projected for FY 2016-17 is over 7600 MUs i.e. a growth of over 9%. This would place a huge strain in terms of demand for power in the coming five years. **In addition to the above, with the coming up of cross-border interconnection i.e. Muzzarpur–Dhalkebar 400 kV line, the demand is likely to grow even at a faster pace as supply will be available from source in India.**

- **New Generation Capacity to be added in the next 5 years**: Currently, 130 MW of hydro capacity is under construction/under execution. Key new projects that are likely to come up include Kulekhani-II (14 MW), Chameliya HEP (30MW), Trisuli-IIIA (60 MW) and Rahughat (32 MW), Budhigandaki (600 MW).

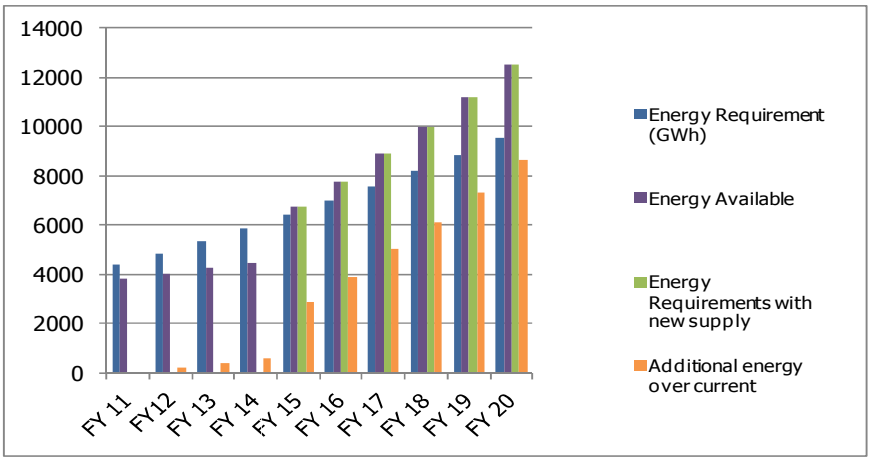
- **Larger IPP participation:** Of the total planned capacity likely to come online in the next five years, a large percentage is to be contributed by the private sector. IPPs under the contractual framework will demand strong payment security mechanism

- **New Transmission Lines:** Significant transmission capacity addition is expected in the next five years with over 12 transmission lines (220 kV and 400 kV) spanning 1200 km to be added. Key lines include Hetauda-Dhalkebar-Duhabi 400kV transmission line spanning 290 km and the Koshi Transmission Corridor with a 220kV transmission line of 110 km. Commissioning of these lines would permit higher imports during the lean hydro seasons, as well as possibility of exports during the high hydro season.

- **Large Quantity of Power Flows in the System with high level of volatility in the system:** With the coming up of new transmission lines particularly the high capacity inter-country lines, the quantum of power flows is likely to increase significantly. In addition, owing to integration with the Indian Grid, the power flows are likely to witness a high level of volatility that will need to be dealt with.

All of the above issues are likely to have considerable impact on the NEA's financial performance and hence are essential elements of the Financial Restructuring envisaged as part of this assignment. Thus, it is essential that the FRP takes into account these realities (and possible scenarios that may emerge) and develop appropriate measures to ensure that the sector moves on a path that is sustainable in the long-run. Figure 6 provides an indication of impact of the sectoral developments in the Nepalese Power Sector (upcoming Muzzarpur–Dhalkebar 400 kV line) on the NEA's finances (based on certain assumptions).

Figure 4.1: Likely Energy Supply/ Demand Scenario with commissiong of the Muzzarpur–Dhalkebar 400 kV line



Source: AF Mercados EMI Analysis

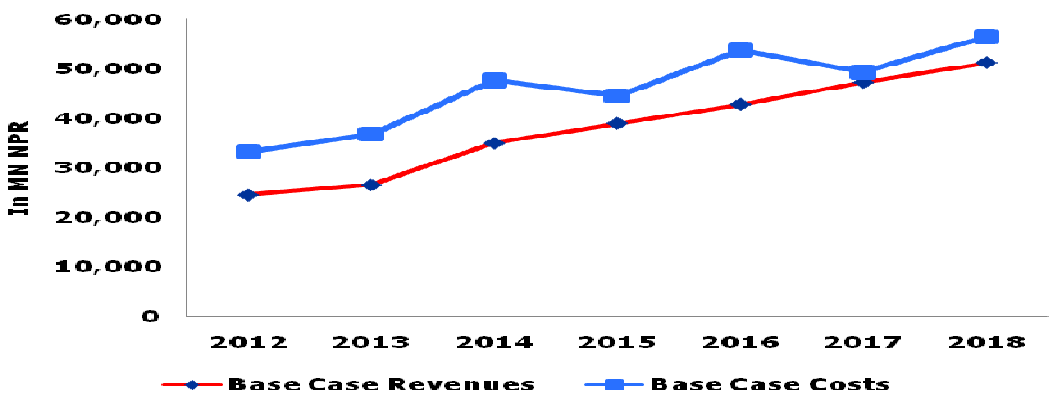
The upcoming Muzzarpur – Dhalkebar 400 kV line is likely to create significant demand pressure within Nepal as it allows higher capacity of electricity transmission as compared to its existing lines of ~100kV. The demand is likely to match up with the energy requirement (or the unconstrained demand). **If NEA caters to the additional energy requirement, the situation can manifest itself into a huge opportunity to earn revenue or a big burden (as NEA loses NRS 3.08 for every unit sold to the consumer) for the NEA. Thus, it will be critical for the NEA to revive its current situation before the above integration occurs**

A major focus of financial recovery plan would be to increase and subsequently reduce the system losses. These measures will no doubt improve NEA's profitability; however the impact of future developments should be tracked. Keeping this mind three scenario have been developed and discussed below

SCENARIO 1(Base Case): No Tariff Hike- Business as Usual

Unless there is significant hike in tariff, the costs will continue to outstrip revenue in future. Going forward by 2018 and afterwards the situation will worsen. The figure below shows that there is a significant gap between the base case revenues and the base case costs.

Figure 4.2: Future Projections with No Tariff Hike

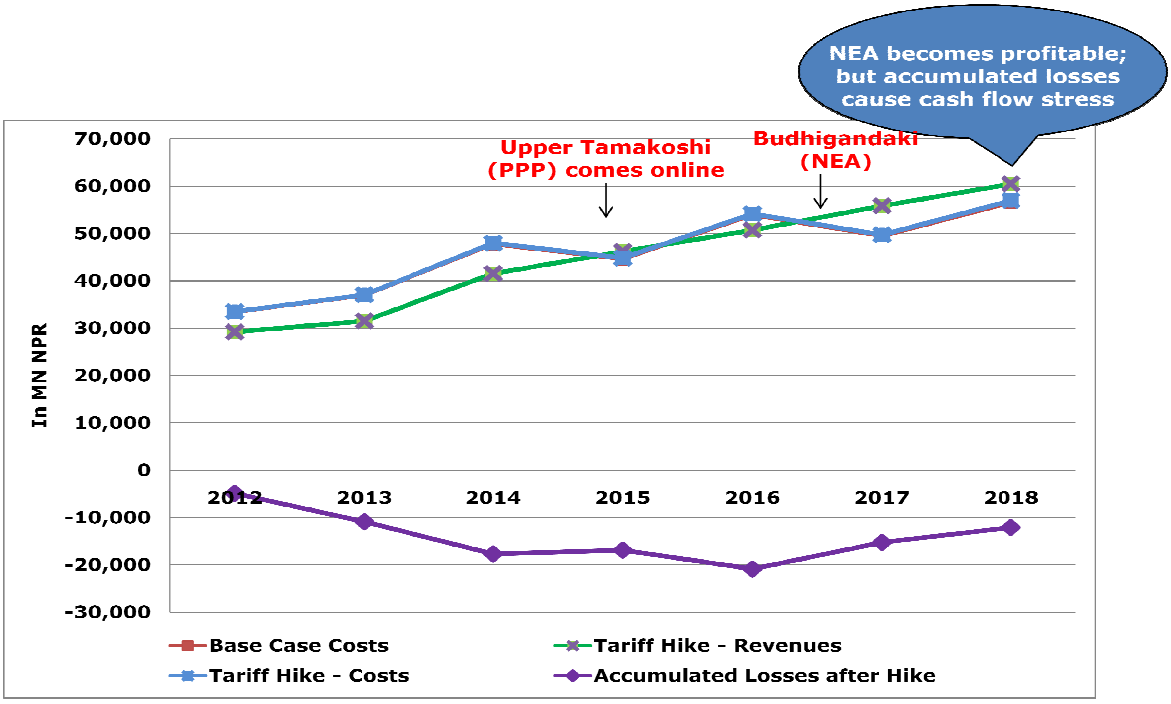


Source: NEA

SCENARIO 2: One time tariff hike of 20% in 2012

AF-Mercados EMI has estimated that with 20% tariff hike in 2012, the situation will improve and NEA will become profitable by 2018. Figure 3.7 below shows the manner in which the sector will shape up going forward.

Figure 4.3: Future Projections with one time tariff hike of 20% in 2012



Source: NEA

Following key points emerge from the above figure:

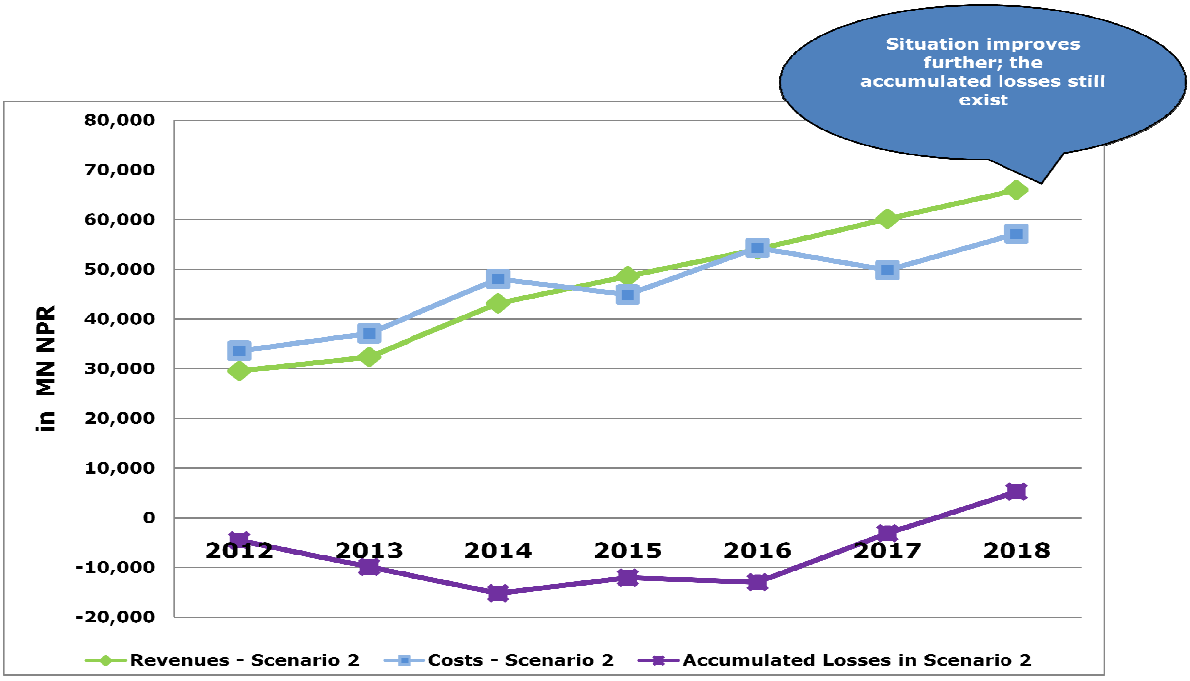
- Even though the accumulated losses have been taken from a base zero in 2012, they are so large in number that they keep on increasing, thus nullifying the affects of tariff increase year on year.
- The gap between cost and revenue will decrease but the major turnaround will happen in 2015 when Upper Tamakoshi Project comes online.
- The same situation will occur with the commission of Budhigandaki Project in the middle of 2016.
- The accumulated losses will continue playing their role in suppressing the profits.
- Thus by 2018 NEA will become profitable but suffer from severe cash stress. The losses will remain but on a lower side.

The point to be noted here is that above analysis is based on the assumption that the projects Upper Tamakoshi and Budhigandaki will come online on time as estimated. However looking at the history of projects in Nepal this seems very unlikely.

SCENARIO 3: One time tariff hike of 20% in 2012 and Loss Reduction of 1% each year starting from 25%

Taking note that tariff hike alone would not be able to tackle the situation; a scenario with loss reduction of 1% each year was considered. Figure 3.8 shows the result that is likely to emerge

Figure 4.4: Future Projections with one time tariff hike of 20% in 2012 and *Loss Reduction of 1% each year starting from 25%*



Source: NEA

Following key points emerge from the above figure:

- There is a significant improvement in margins with revenues surpassing costs in the middle of 2014. Profits become more prominent after 2016 and tend to increase after 2018.
- Inspite of gradual reduction, accumulated losses will exist even beyond 2018

Looking at the above analysis it is imperative that the impact of future developments need to be carefully tracked to ensure that potential risks are obviated. Some of them are:

1. **Delay in Commissioning of Upper Tamakoshi (450 MW) – Scheduled for 2015 – *What happens when the plant gets delayed by 2 years***
2. **Cost of India Procurement Increases**
3. **Commissioning of Muzaffarpur –Dhalkebar Line**
4. **Unfavourable Foreign Exchange Variations**

V ANNEXURES

Model Assumptions

Generation Capacity & CODs											
Upcoming Plants of NEA	***Cons Year***	***Cod Year***	***MW***	***Exp. Generation***	***Capacity Ftr***	***Cost in Bn NPR***	***Capex Done***	***Adl. Capex***	***Total $ Mn***	***D/E Ratio***	***NEA Stake in Equity***
Kulekhani-III	2006	2013	14	40.85	33%	2.33	0.553	1,781	29.9	4	0%
Chameliya	1997	2013	30	184.21	70%	9.38	2.070	7,305	120.0	4	50%
Upper Trishuli 3A	2006	2014	60	460.00	88%	5.70	0.019	5,681	72.9	4	50%
Ruhughat	2008	2014	30	186.00	71%	4.91	0.014	4,898	62.9	4	50%
Upper Trishuli 3B	2008	2014	37	296.00	91%	5.10	0.015	5,085	65.3	4	50%
Budhigandaki SHEP	2009	2017	600	2500.00	48%	42.12	0.677	41,440	539.0	4	50%
Upper Seti Storage - Storage Project	2013	2018	127	484.00	44%	26.65	0.036	26,610	341.0	4	50%
Tamakoshi VHEP	2014	2018	87	446.00	59%	11.17	0.000	11,170	142.9	4	50%
Nalsyagu Gad - Storage Project	2015	2020	400	889.00	25%	28.99	0.007	28,982	371.0	4	50%
Tamor Storage Project	2015	2020	382	1673.00	50%	28.99	0.001	28,989	371.0	4	50%

Existing Plants of NEA	***COD Year***	***MW***	***Exp. Generation***	***Int. Cons.***	***Net Sold***	***Capacity Ftr***
Panauti Hydro Power	1966	2	1,880	240	1,640	9%
Trisuli H.P.	1967	21	114,939	745	114,194	62%
Fewa (Pokhara) H.P.	1970	1	2,180	18	2,162	23%
Sunkoshi H.P.	1972	10	60,594	500	60,094	69%
Tinau H.P.	1974	1	6,000	80	5,920	67%
Gandak H.P.	1979	15	20,525	650	19,875	16%
Kulekhani-I H.P.	1983	60	75,114	1,200	73,914	14%
Devighat H.P.	1984	14	81,438	350	81,088	66%
Seti H. P.	1985	2	10,870	34	10,836	83%
Kulekhani-II H.P.	1986	32	36,935	250	36,685	13%

Marsyangdi Hy. Pro	1989	69	404,805	1,220	403,585	67%
Tatopani H.P.	1995	2	13,000	19	12,981	74%
Ilam Puwa H.P.	2000	6	31,683	52	31,631	58%
Modi H.P.	2001	14	62,521	226	62,295	51%
Kaligandaki 'A' H.P.	2003	144	753,368	2,954	750,414	60%
Middle Marsyangdi Hydro P	2009	70	169,000	400	168,600	28%

PPP - NEA /GoN owned Plants	**Const**	**COD**	**Capacity (MW)**	**Expected Gen (GWh)**	**Capacity factor (%)**	**Project Cost (Bn NPR)**	**Project Cost (MM USD)**	**D/E Ratio**	**NEA Share of Equity**	**Investment done ($ Mn)**	**Investment due ($ Mn)**
Upper Tamakoshi	2009	2015	456	2281	57.11%	34.00	435	2.33	41%	16.64	418.48
Upper Modi A	2010	2014	42	202	55%	4.00	51	2.33	51%	1.47	49.72

IPPs			
Planned Projects	**COD FY**	**MW**	**Remarks**
Belkhu		0.32	PPA concluded
Golmagad		0.58	PPA concluded
Lower Piluwa		0.99	PPA concluded
Mai		2.40	PPA concluded
	2011	**4.29**	
Lower Indrawati		4.50	PPA concluded
BhairabKunda		1.85	PPA concluded
Jiri		0.99	PPA concluded
Lower chaku		1.76	PPA concluded
Biomass		0.50	PPA concluded

Phawa		4.95	PPA concluded
Tinau		0.99	PPA concluded
Total	2012	**15.54**	
Siuri		4.95	PPA concluded
Chake		0.99	PPA concluded
Hewa		2.40	PPA concluded
Lower Nyadi		4.50	PPA concluded
Tadi		3.50	PPA concluded
Lower Modi 1		9.90	PPA concluded
Mailung		5.00	PPA concluded
Sipring		9.70	PPA concluded
Charnawati		0.98	PPA concluded
Dapcha Roshi		4.90	PPA concluded
Upper Puwa		9.80	PPA concluded
Total	2013	**56.62**	
Madi		10.00	PPA concluded
Upper Mai		3.10	PPA concluded
Dharam khola		5.00	PPA concluded
Sanjen		35.00	Private
Uppersanjen		12.00	Private
Upper Modi A		42.00	NEA private JV
Total	2014	**107.10**	
Balephi		20.00	Private
Kabeli A		30.00	Private

Upper Marsyangdi A		50.00	Private
Total	2015	**100.00**	

Transmission Lines Capex								
Project	***Cons. Year***	***COD Year***	***Length (km)***	***Total $ Mn***	***Bn NPR Spent***	***Blc. Capex***	***D/E Ratio***	NEA vs GoN
Thankot-Chapagaon-Bhaktapur 132 kV TL	2009	2011	28	23.00	0.94	1,703	4	50%
Khimti-Dhalkebar 220 kV TL	2009	2013	76	29.74	0.61	2,263	4	50%
Chandranigahapur System Reinforcement (132 KV SS & 33 KV TL)	2009	2011	74	5.26	0.07	404	4	50%
Butwal-Kohalpur 132 kV TL 2nd Circuit Stringing	2010	2013	208	13.80	0.00	1,078	4	50%
Mid Marsyangdi-Dumre-Damauli-Marsyangdi 132 kV TL	2010	2013	45	16.60	0.00	1,297	4	50%
Pathlaiya 132 KV Substation	2010	2013	0	5.40	0.00	422	4	50%
Shyangja 132 kV S/S	2010	2013	0	6.60	0.00	515	4	0%
Matatirtha 132 KV Substation Extension	2010	2013	0	3.30	0.00	258	4	50%
Chapali 132 KV Substation	2010	2013	0	16.00	0.00	1,250	4	50%
Hetauda- Bharatpur 220 KV Tr Line	2009	2013	70	31.00	0.00	2,422	4	50%
Baneshwor-Bhaktapur UG Cable 132kV	2009	2013	40	29.30	0.00	2,290	4	50%
Kabeli Corridor 132 kV TL	2009	2014	79	35.62	0.01	2,782	4	0%
Bharatpur-Bardghat 220 kV TL	2009	2014	70	31.00	0.13	2,409	4	50%
Singati-Lamosanghu 132 kV TL	2009	2015	38	13.00	0.00	1,015	4	0%
Marsyangdi-Kathmandu 220 kV	2009	2014	85	46.70	0.01	3,649	4	0%
Hapure-Tulsipur 132 kV TL	2009	2015	22	6.30	0.00	492	4	0%
Modi -Lekhnath 132 KV TL	2010	2014	45	14.80	0.00	1,156	4	0%
Kaski-Bhurjung-Parbat-Kusma 132 KV TL	2010	2014	45	14.25	0.00	1,113	4	0%
Lekhnath-Damauli 132 kV DC	2010	2014	40	31.50	0.00	2,461	4	0%
Kohalpur-Surkhet 132 kV	2010	2016	55	15.88	0.00	1,241	4	0%
Hetauda-Dhalkebar 400 KV TL	2010	2015	140	76.00	0.00	5,939	4	50%
Dhalkebar-Duhabi 400 KV TL	2010	2015	160	85.00	0.00	6,642	4	50%

Marsyangdi Corridor 132 kV TL	2010	2015	45	11.90	0.00	930	4	0%
Sunkoshi-Dolakha Corridor 132 kV TL	2010	2015	20	8.00	0.00	625	4	0%
Koshi Corridor (Kusaha-Basantpur)220 kV TL	2010	2015	90	44.88	0.00	3,507	4	0%
Samudratar-Naubise TL	2010	2015	50	15.13	0.00	1,182	4	0%
Ramechhap-Garlyan-Khimti TL	2010	2015	50	16.63	0.00	1,299	4	0%
Chilime-Trisul-Galchhi TL	2010	2015	60	18.38	0.00	1,436	4	0%
Butwal-Sunavli	2009	2016	60	16.75	0.00	1,309	4	50%
Kaligandaki Corridor 220/132 kV TL	2010	2016	150	40.25	0.00	3,145	4	0%
Solu Corridor TL	2010	2016	70	25.00	0.00	1,954	4	0%
Mid. Marsyangdi-Manang TL	2011	2017	60	16.75	0.00	1,309	4	0%
Khimti-Kathmandu 220 KV TL	2011	2017	0	57.50	0.00	4,493	4	0%
Bajhang-Dipayal-Attariya TL	2011	2018	100	28.25	0.00	2,207	4	0%
Surkhet-Dailekh-Jumla TL	2010	2018	110	31.86	0.00	2,490	4	0%
Kaligandaki-Jhimruk TL	2011	2018	110	20.13	0.00	1,573	4	0%
Gulmi-Arghakhanchi-Chanauta TL	2010	2018	90	20.13	0.00	1,573	4	0%
Trishuli 3B Hub Substation	2009	2016	60	9.40	0.00	735	4	0%
Modi-Lekhnath TL*	2010	2014	22	10.25	0.00	801	4	0%
Hetauda, Kamane 132 KV Substation, 33kV Tr. Line**	2010	2013	10	3.50	0.00	273	4	0%
Kusum-Hapure 132 KV Transmission line**	2010	2013	22	6.25	0.00	488	4	0%
Mirchaiya- Katari 132 kV TL**	2010	2015	20	7.50	0.00	586	4	0%

Financing Assumptions					
Generation Projects			***Transmission Lines***		
Interest Rate	%	8%	Interest Rate	%	9%
Interest Rate during Construction	%	8%	Interest Rate during Construction	%	9%
Tenor	Years	6	Tenor	Years	6
Working Capital					
Interest Rate	%	12%			

Foreign Exchange Assumptions																			
NPR/USD		78.1	2011																
INR/USD		49.1																	
Depreciation NPR	%	3.00 %																	
Depreciation INR	%	3.00 %																	
Year		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NPR/USD		65.44	67.40	69.43	71.51	73.65	75.86	78.14	80.48	82.90	85.39	87.95	90.59	93.30	96.10	98.99	101.95	105.01
INR/USD		41.12	42.35	43.62	44.93	46.28	47.67	49.10	50.57	52.09	53.65	55.26	56.92	58.63	60.39	62.20	64.06	65.99

Working Capital Assumptions			
Inventories		% Sales	15%
Sundry debtors		% Sales	33%
Loans & Advances		% Sales	17%
Sundry Creditors		% Sales	50%
Provisions		% Sales	23%
Margin Money		% Sales	25%

Demand Curve Assumption	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021							
Assumed PeakDemand(MW)		558	603	648	722	813	885	946	1,057	1,163	1,272	1,387	1,510	1,641	1,770	1,907	2,052	2,206							
Net Energy Consumption (Gwh) / Sold		2,643	2,781	3,052	3,186	3,131	3,712	3,858	4,851	5,350	5,860	6,404	6,984	7,604	8,219	8,870	9,563	10,300							
NEA Estimates																									
PeakDemand(MW)									1,057	1,163	1,272	1,387	1,510	1,641	1,770	1,907	2,052	2,206	2,363	2,545	2,741	2,951	3,177	3,419	3,67
Energy Consumption Gwh									4,851	5,350	5,860	6,404	6,984	7,604	8,219	8,870	9,563	10,300	11,054	11,929	12,870	13,882	14,971	16,143	17,44
Historical Growth Curve																									
PeakDemand(MW)	9.21%	558	603	648	722	813	885	946	1,033	1,128	1,232	1,346	1,470	1,605	1,753	1,915	2,091	2,284							
Energy Consumption Gwh	6.51%	2,643	2,781	3,052	3,186	3,131	3,712	3,858	4,110	4,377	4,662	4,966	5,289	5,633	6,000	6,390	6,807	7,250							
Custom Curve																									
Year		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021														
Growth in Industrial Demand		8%	8%	8%	8%	8%	8%	8%	8%	8%	8%														
Economic Growth		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%														
Improvement in Transmission		4%	4%	4%	4%	0%	0%	0%	0%	0%	0%														
	Base 2011																								
Peak Demand (MW)	946	1,005	1,068	1,135	1,206	1,269	1,336	1,406	1,480	1,557	1,639														
Energy Consumption (Gwh)	3,858	4,100	4,356	4,628	4,917	5,175	5,447	5,733	6,034	6,351	6,684														
Internal Consumption		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%												
Export		10%	2%	3%	3%	2%	2%	2%	2%	3%	3%	3%	2%												

Electricity Tariffs												
Tariff Indices- Year on Year esclations	Escalations		5%	10%	7%	5%	5%	5%	5%	5%	5%	5%
Categories of Consumers		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Domestic		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Non-commercial		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Commercial		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Industrial		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Water supply		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Irrigation		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Street-Light		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Temporary		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Transport		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Temple		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Community		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Internal Consumption		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Export		1.00	1.04	1.07	1.04	1.02	1.02	1.02	1.02	1.02	1.02	1.02

Average Tariffs - Projection													
Categories of Consumers		2010 Avg.											
Domestic	NPR/kwh	6.64	6.64	6.90	7.39	7.68	7.84	7.99	8.15	8.31	8.48	8.65	8.82
Non-commercial		9.36	9.36	9.73	10.42	10.83	11.05	11.27	11.50	11.73	11.96	12.20	12.44
Commercial		9.36	9.36	9.73	10.42	10.83	11.05	11.27	11.50	11.73	11.96	12.20	12.44
Industrial		6.30	6.30	6.55	7.01	7.29	7.44	7.59	7.74	7.89	8.05	8.21	8.38
Water supply		4.88	4.88	5.08	5.43	5.65	5.76	5.88	6.00	6.12	6.24	6.36	6.49
Irrigation		3.88	3.88	4.04	4.32	4.50	4.59	4.68	4.77	4.87	4.96	5.06	5.16
Street-Light		6.70	6.70	6.97	7.46	7.75	7.91	8.07	8.23	8.39	8.56	8.73	8.91
Temporary		13.50	13.50	14.04	15.02	15.62	15.93	16.25	16.58	16.91	17.24	17.59	17.94
Transport		5.06	5.06	5.27	5.63	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
Temple		5.29	5.29	5.50	5.88	6.12	6.24	6.37	6.49	6.62	6.76	6.89	7.03
Community		3.59	3.59	3.74	4.00	4.16	4.24	4.32	4.41	4.50	4.59	4.68	4.78
Internal Consumption		8.98	8.98	9.34	9.99	10.39	10.60	10.81	11.03	11.25	11.47	11.70	11.94
Export		6.88	6.88	7.16	7.66	7.97	8.13	8.29	8.45	8.62	8.80	8.97	9.15

Power Purchase tariff - Escalations												
	2010		**Year on year tariff escalation**									
	NR/kWh	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Power purchased from NEA Subsidiaries/PPPs	4.00	0.0%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Power purchased from Nepal IPPs	7.60	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Power purchased under exchange agreement with India	4.02	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Power Purchase from India on commercial basis	10.72	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%

Operating Costs - Escalations & Efficiency Improvements

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Efficiency Improvement	0%	0%	1%	3%	3%	3%	3%	3%	3%	3%	3%
Escalation in Fuel,Salary, Wages & Allowance	0%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Escalation in O&M Costs	0%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%

Generation Assumptions

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capacity Factor	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Auxiliary Power	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Export	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
System Losses	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%

Split of Energy by Type																				
Year				2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NEAHydro	Gwh		5.69%	1,523	1,569	1,747	1,793	1,840	2,109	2,122	2,184	2,387	2,989	2,982	2,991	5,835	6,821	6,810	10,558	10,48
NEAThermal	Gwh		-20.70%	14	16	13	9	9	13	3	3	3	3	3	3	3	3	3	3	3
India(Purchase) - Max	Gwh	5%	19.25%	241	266	329	425	356	639	694	729	765	803	844	886	930	977	1,025	1,077	1,131
Nepal(IPP) - Max	Gwh	5%	3.10%	865	930	962	958	926	951	1,039	1,091	1,145	1,203	1,263	1,326	1,392	1,462	1,535	1,612	1,692
Total Purchases	Gwh			1,106	1,196	1,291	1,384	1,282	1,590	1,733	1,820	1,911	2,006	2,106	2,212	2,322	2,438	2,560	2,688	2,823
AvailableEnergy(GWh)	Gwh			2,643	2,781	3,052	3,186	3,131	3,712	3,858	4,007	4,301	4,998	5,092	5,206	8,161	9,263	9,373	13,250	13,31
System Losses	%		2.23%	24.8%	25.1%	26.7%	26.5%	25.3%	28.9%	28.4%	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%	28.35%
Same Losses Continue		0.00%									28.4%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%
1% reduction each year		1.00%									27.4%	26.4%	25.4%	24.4%	23.4%	22.4%	21.4%	20.4%	19.4%	18.4%
0.5% reduction each year		0.50%									27.9%	27.4%	26.9%	26.4%	25.9%	25.4%	24.9%	24.4%	23.9%	23.4%