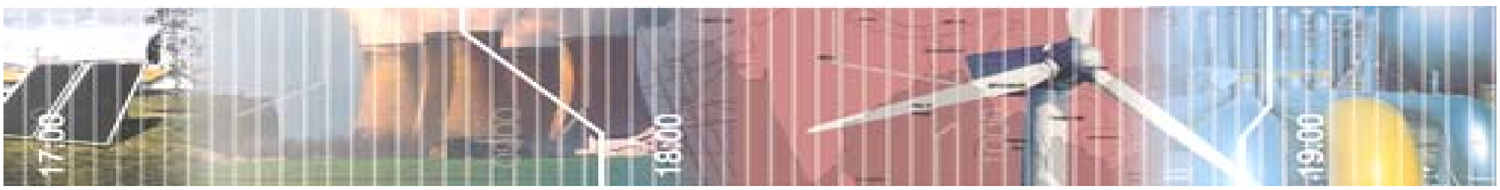
TRANSCO

TRANSMISSION DEVELOPMENT PLAN



March 2003

TABLE OF CONTENTS

TRANSMISSION DEVELOPMENT PLAN

Introduction

This 10-year Transmission Development Plan ("*TDP*" or "*Plan*") has been prepared by the National Transmission Corporation ("*TRANSCO*") to comply with its mandate under Section 9(f) of Republic Act 9136, the Electric Power Industry Reform Act of 2001 ("*EPIRA*").

The Plan sets out the manner in which TRANSCO aims to promote reliable, adequate, secure, and stable service for all users of the nation-wide electricity transmission system. It reflects the planning criteria documented by the Philippine Grid Code and the performance targets established by the Energy Regulatory Commission. The Plan also provides an indicative capital investment program for the identified projects and programs.

The TDP has been prepared following consultation with industry participants. TRANSCO has used an iterative process of simulation to determine the appropriate additions, expansions, reinforcements and improvements of the transmission backbone.

As required by the EPIRA, TRANSCO will seek approval from the Energy Regulatory Commission ("ERC") for its individual investment plans within the broad context of this TDP. DOE approval of this TDP and its incorporation into the Philippine Energy Plan (PEP) in no way negates the requirement for ERC approval. The ERC's determination will prevail in the event of a conflict between the indicative capital investment program in the TDP and the investment plans which are approved by the ERC.

As the TDP must be prepared on an annual basis, TRANSCO anticipates that the TDP would be amended from time to time to reflect the ERC's rulings on the proposed investment plans.

The ERC has issued Draft Guidelines on the Methodology for Setting Transmission Wheeling Rates for 2003 to 2027. These Draft Guidelines provide for ERC approval of the proposed capital investment program for each regulatory period (3-5 years) in advance of each period. TRANSCO expects that future TDP will provide a vision for each ten-year TDP period but will also reflect the ERC's determination regarding specific investment plans, in order to minimize any risk of conflict between the TDP and the investment plans approved by the ERC.

TRANSCO Roles and Reponsibilities

The Electric Power Industry Reform Act (the "EPIRA" or the "Act") became effective on 26 June 2001 and established the necessary legal framework to enable full restructuring and privatisation of the power industry. Under the new structure, the electricity industry in the Philippines was officially segregated for regulatory purposes into the separate functional areas of Generation, Transmission, Distribution and Supply. TRANSCO was created independent of Generation and Distribution and Supply, as a regulated natural monopoly. As part of the Electric Power Industry Reform Act (EPIRA) a requirement was placed on TRANSCO to prepare a Transmission Development Plan.

A new focus for TRANSCO has been established to become a self-financing business complying with a set of transmission service standards established by the Energy Regulatory Commission and documented in the Philippine Grid Code. The Energy Regulatory Commission will also regulate the transmission charges to be levied by TRANSCO

Duties of TRANSCO under the Electric Power Industry Reform Act

As the monopoly electricity transmission service provider in the Philippines, TRANSCO has the authority and responsibility for planning, construction, centralized operation and maintenance of the high voltage transmission facilities (including, as the system operator, grid interconnections and ancillary services) in the Philippines.

The key functions and responsibilities of TRANSCO or its Concessionaire as defined in the EPIRA include:

- to provide open and non-discriminatory access to its system to all electricity users;
- to ensure and maintain the reliability, adequacy, security, stability and integrity of the Grid;
- to prepare the Transmission Development Plan in consultation with Electric Power Industry Participants;
- to improve and expand its transmission facilities consistent with the Transmission Development Plan and the Philippine Grid Code.

The Philippine Grid Code

The Grid Code establishes and documents the basic rules, requirements, procedures and standards that govern the operation, maintenance and development of the high voltage backbone transmission system in the Philippines.

The responsibilities of TRANSCO or its Concessionaire can be classified into the following roles as defined in the Grid Code:

- *Grid Owner*: the party that owns the high voltage backbone Transmission system and is responsible for maintaining adequate Grid capacity in accordance with the provisions of the Grid Code.
- *System Operator*: the party responsible for the Generation dispatch, the provision of Ancillary Services, and operation and control to ensure safety, Power Quality, Stability, Reliability and the Security of the Grid.

The operational responsibilities of all grid users are set out in the Grid Code. The specific responsibilities of the Grid Owner and System Operator are summarised in Table 0.1. TRANSCO will assign its responsibilities to the Concessionaire via the Concession Agreement. (The SO functions will remain with TRANSCO until the Concessionaire has a franchise, they will then also transfer.)

Table 0.1 **Operational Responsibilities** of the Grid Owner

Grid Owner
• Provide and maintain all grid equipment and facilities, including those required for power quality • Design, install and maintain the grid's protection system • Ensure safe and economic grid operating procedures are followed at all times • Prepare the Grid Operating and Maintenance Program (jointly with the System Operator) • Execute the instructions of the System Operator during emergency conditions

Process for Preparing the TDP

The EPIRA sets as a key responsibilities of TRANSCO or its Concessionaire, the preparation of the Transmission Development Plan in consultation with Electric Power Industry Participants. As provided in the EPIRA, the Transmission Development Plan prepared by TRANSCO or its Concessionaire will be submitted for the approval of the Department of Energy ("*DoE*"). It will be consolidated into the Philippine Energy Plan ("*PEP*") for submission to Congress on 15 September each year.

This Transmission Development Plan will be updated on an annual basis to maintain a ten-year or longer planning horizon. The information contained in this document and its appendices relates to the planned development of the Philippine national electricity transmission network, as maintained and operated by TRANSCO or its Concessionaire following pivatization.

The annual process for the preparation and approval of the TDP is as follows:

July	TRANSCO publishes its draft TDP for the next 10 year period
August	The DoE considers the draft TDP and, if necessary, requests further clarification and/or amendments from TRANSCO.
September	The DoE approves the TDP and consolidates it into the PEP

In revising the TDP each year TRANSCO will take into consideration a number of factors that will affect the development and on-going performance of the transmission network. These factors will include but are not limited to:

- Demand projections;
- Network performance as measured by the defined standards which ERC will pomugate;
- Current and projected generation capacity;
- Identified transmission constraints.

Network Performance

Measures to Improve Performance

The standard of system performance refers to the number of interruptions in the delivery of power to consumers caused by various factors related to the transmission system. In future, measures of performance will be based upon the root causes of faults as determined by the new measures for reporting network performance [described in section 3.1.1 below]. TRANSCO's capital expenditure program aims to reduce the number of interruptions.

The following are among the usual causes of power interruptions in the Philippine transmission system:

- malfunction of protective relaying system or simultaneous generator tripping, resulting in wide-area blackouts;

- imbalances on supply and demand caused by generator tripping, resulting in frequency drops that requires automatic load dropping;

- facility trouble that results in forced outage of lines and other devices such as broken insulators with flashovers caused by lightning and smog pollution, hot spot at connectors, or vegetation clearance under the transmission lines.

All such interruptions translate to problems in power quality which must be mitigated in compliance with the Grid Code. Among the measures being undertaken by Northern Luzon Region, as a pilot for the rest of the country, on connection or modification requirements under Section 5.3 of the Grid Code are the following:

- Safety Rules - compliance to standards of the Philippine Electrical Code and the Occupational Safety & Health Standard.
- Test and Commissioning Programs - ensure that equipment connected or to be connected to the Grid are designed, manufactured, tested and commissioned based on quality standards of ISO 9000.
- Protection Arrangements - ensure that protections of Grid equipment are designed, co-ordinated and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impacts of fault to the Grid.
- Maintenance Standards - ensure that Grid equipment are operated and maintained m accordance to Good Industry Practice, e.g. RCM, MMP, ZOP.
- Transformer Connection and Grounding - make certain that equipment to be connected to the Grid complies with the Grid Code requirements.
- Under-frequency Relays for Automatic Load Dropping - guarantee that under-frequency relays comply with the specification requirements of the Grid Code and ensure suitability for operation.

There are two focus areas in order to deliver improved performance.

Firstly, fault avoidance, through proactive initiatives, such as regular use of line inspections with timely programmed follow-up actions (vegetation management, replacement of broken insulators etc.). This allows incipient or potential faults to be addressed as part of the planned work programme, without sustaining outages with the resultant emergency remedial works.

Secondly, fault impact minimization, achieved through rigorous contingency planning, defining circuit outage strategies, including the implementation of effective protection schemes. Such initiatives will reduce the impact of a fault both in terms of customers affected and outage duration and hence improve the performance of the network.

The historical performance of these networks is not on a par with most world standards. Even allowing for the problems experienced in most island networks which suffer extreme weather conditions like lightning storms and high wind, performance is still poor and TRANSCO acknowledges that there is considerable room for improvement.

Vegetation management is a very effective way of improving performance with little effort as long as it is effectively targeted and effectively managed. The effective targeting implies that there is good reporting of failures, which will allow the subsequent analysis to take place to facilitate effective targeting improvements. We will initiate a vegetation management program initially in known problem areas.

With regard to the perceived failure of protection discrimination we will put more effort into the training of the relevant engineers. Another area for consideration is the supply restoration and repair procedures for emergency no-supply situations. In the past the procedure as within many companies was to locate and repair the fault first and restore supply secondly. The current best practice is to restore supplies to as many as possible and then secondly to repair the fault.

TRANSCO aims to carry out an in depth review of its current operational procedures and safety rules in order to improve the network performance for customers and the operational safety of its employees and contractors.

Summary of Measures to Improve Performance

- To purchase a Fault and Incident Reporting System to provide consistent and accurate data across all three grids which will allow the subsequent analysis to take place to facilitate effective targeting improvements.
- To set performance targets based upon the performance of comparable countries and with a year on year improvement element.
- To instigate a system of line inspections with accurate and consistent reporting.
- To provide training to ensure the correct design and application of protective systems
- To instigate a system of effective vegetation management

- To carry out an in depth review of our current operational procedures and safety rules in order to improve the network performance for our customers and the operational safety of our employees and contractors.

Demand Projection

The long-term projection of electricity requirement is correlated with the Gross Domestic Product (GDP) forecast. This year the low GDP forecast from the National Economic and Development Authority (NEDA) foresees the economy to grow from 3.2% in 2001 to 4.0% in 2002(actual 4.6%), 5.4% in 2003, 5.7% in 2004, 6.1% in 2005, 6.3% in 2006 and 5.2% from 2007-2012.

Using econometric modelling and trend extrapolation, current projections show the total system demand growing at a compounded growth rate of 7.8% during the first 5-year (2003-2007), decreasing to 7.3% for the period 2008-2012, or an average growth of 7.5 % for the 10-year period. This will increase demand from a level of 8,248 MW in 2002 to 17,032 MW by year 2012. Table 4.1 shows the projected demand by area.

TABLE 4.1
Summary Of Demand Forecast Per Area

GRID	2001	2002	2005	2007	2010	2012
LUZON						
NLR		1,407	1,752	2,043	2,524	2,907
MM		3,532	4,399	5,130	6,339	7,299
SLR		1,369	1,705	1,988	2,456	2,828
Luzon-Total	**5,618**	**6,308**	**7,855**	**9,161**	**11,319**	**13,034**
VISAYAS						
Cebu		410	508	586	719	824
Negros		183	226	262	321	368
Panay		162	200	231	283	324
Leyte		150	187	216	265	304
Samar		26	32	38	46	49
Bohol		35	46	82	119	138
Visayas-Total	**893**	**941**	**1,167**	**1,377**	**1,707**	**1,957**
MINDANAO						
NWMA		139.8	175	204	250	285
LANAO		134.9	169	197	241	275
NCMA		153.2	192	223	274	313
NEMA		134.5	167	196	241	274
SEMA		274.4	344	400	491	560
SWMA		163.2	205	238	292	333
Mindanao-Total	**954**	**1,000**	**1,254**	**1,459**	**1,789**	**2,041**
PHILIPPINES	**7,465**	**8,249**	**10,276**	**11,997**	**14,815**	**17,032**

Planning Assumptions and Criteria

The long-term strategy of the TDP focuses on attaining a unified grid for the country, while ensuring an economically adequate and reliable transmission system. The main thrust for this unification will come form the adoption of unified design standards, operating procedures and reporting systems.
The primary planning assumptions and criteria are as follows:
- The plans must be the least cost option
- The plans must able to achieve the performance standards of the PGC and the performance targets set by the ERC
- The plans must have evaluated the costed alternatives

Transmission networks have several functions:
- The transmission of power in large quantities from large generation to large demand centres.
- The distribution of power in quantity to substations supplying lower-voltage networks over the whole area of supply.
- The pooling of generation at all levels on demand so that power is generated from the cheapest sources.
- The pooling of generation and demand so that variations from forecasts can de shared and met with minimum additional plant.

These functions can be achieved most easily with a meshed grid network since:
- Many points can be interconnected over a wide geographical area.
- Continuity of supply against outages can be provided.
- Individual circuit capability may be increased - change in transfer impedance with outage is reduced
- Total capability is increased since utilisation is improved with more circuits in parallel

The long-term strategy of the TDP will focus on the development of the 500kV-meshed grid network (i.e. a meshed network where there are multiple paths between generation and load centres on the network)for Luzon and the 138kV-meshed grid networks for Visayas and Mindanao.

Interconnection Strategy

The interconnection of small island grids is also being considered to provide a reliable supply of power compliant with the revised supply reliability standards. The interconnection policy will also depend upon minimising the demand being served from oil-based plants.

In general, grid inter-ties can give added flexibility to utility operations, and lower the total system requirement for reserves and back-up power when used in conjunction with a pragmatic security of supply standard. (Note, interconnects are circuits within a meshed network, whereas inter-ties are circuits that connect separate grids together via a single path.) It could also help maximise the full utilisation of indigenous energy sources in support to DoE direction for energy self-reliance. The decision to implement such an inter-tie strategy, however, depends on quantifying the economic benefit of each inter-tie to be able to justify the total cost of the project.

Planning Criteria

There are two main sets of planning criteria, the power quality standards and the transmission planning criteria.

Power Quality Standard

The Power Quality Standards are laid down in the "Philippine Grid Code" (PGC) produced by the Energy Regulatory Commission (ERC). These are in the main related to the purity of the voltage (its sinusoidal waveform) and relate to harmonics, dips and sag. These parameters are influenced in the main by disturbing loads and by the impact of HVDC links. A transmission company has very little control of these factors other than by policing and mitigating against the connection of "dirty loads" when they are requested.

The power quality standard is defined as the quality of the voltage, including its frequency and resulting current, that are measured in the grid during normal conditions. To ensure power quality, the system should not experience one of the following conditions that significantly affect the normal operations of the system:

a) The system frequency has deviated from the nominal value of 60 Hz;
b) Voltage magnitudes are outside their allowable range of variation;
c) Harmonic frequencies are present in the system;
d) There is imbalance in the magnitude of the phase voltages;
e) The phase displacement between the voltages is not equal to 120 degrees;
f) Voltages fluctuations cause flicker that is outside the allowable flicker severity limits;
g) High-frequency over-voltages are present in the grid.

The Transmission Planning Criteria

The Transmission Planning Criteria is the response of the transmission company to achieve the targets set by Network Reliability or Performance standards set in the Grid Code. It establishes the baseline indices (N-1 rule, thermal criteria, voltage criteria and stability criteria) for the conduct of system reliability impact studies (SRIS). These studies are needed to be able to identify system congestion, impact of new loads or generators and the expansion of the system to prevent transmission instability, uncontrolled separation of lines, cascading outages. These failures can result to blackouts or voltage collapse. By meeting these criteria the transmission system will continuously and accurately meet its system control and power flow obligations. Thus, meeting the standard requirements of the Grid Code while keeping all parts of the transmission system in service during single failures, maintenance and refurbishment or commissioning of new lines.

Table 5.1 shows the transmission planning criteria and they are briefly described as follows:

N-1 Rule

The N-1 rule refers to the planning criterion wherein any loss of one element of the power system (i.e., a generator, a transmission line, or a transformer) should not have degrading effect on the security of the whole system. On the occurrence of the failure of one element (N-1), the system should meet the following conditions:

The generators must remain stable.
The under-frequency load shedding must not be activated
The power flows must remain lower than the rating of the network equipment and must not overload the remaining element.
The bus voltages must remain within the limits (as stated in the PGC and reiterated in section 5.2.2.3).

In compliance with the conditions defined in the (N-1) Rule, the following more detailed criterion are observed in the planning process.

Thermal Criteria

Power flows on any generator, transmission fine, transformer, and or conditioning device connected to the transmission system should be maintained within the thermal capacity ratings. These thermal capacity ratings are defined as follows:

<u>Normal Capacity Rating</u> represents loading limit or thermal Emit that can be sustained indefinitely without increased risk of equipment failure or loss of life.

<u>Emergency Capacity Rating</u> represents loading limit or thermal limit that can be tolerated for a relatively period of time to allow time for operator's corrective action following a disturbance in the system. It must be recognized that at this loading level, there may be a small increase in equipment's risk of failure or loss of fife. This increased risk is allowed on the basis that the events that cause such operation rarely occur and that operation within emergency limits may avoid shedding of customer load.

Voltage Criteria

Voltage control is necessary to avoid damage to connected grid and equipment from both under and over voltages. Maintaining grid voltages at or near maximum safe levels reduces system losses and reduces vulnerability to voltage collapse and steady state and transient stability problems. Voltage unbalances, voltage fluctuations and harmonics shall also be controlled to ensure quality of power service. Voltage variations in the system shall remain within ±5% of the nominal value during normal conditions and ±10% during single outage contingency events. Voltage may temporarily exceed ±10% during severe grid emergencies and restoration.

Stability Criteria

All generators and large machines connected to the transmission system should remain in synchronism and maintain stable operation during normal and loss of single-element (N-1) contingency events. Stability simulation provides information on the frequency and voltage variations in the system, including time of recovery to normal operating level after an occurrence of fault. The criteria define the appropriate generator controls, additional power conditioning devices and transmission system reinforcements that may be necessary to maintain stable operation of the system.

Table 5.1 Summary Of Transmission Planning Criteria

ACCEPTABLE LIMITS	ALLOWABLE REMEDIAL ACTIONS
Normal Condition	
Transmission line loading < 100 % Transformer loading: < 100% Steady-state voltage range: +/- 5%	Line reinforcements Transformer additions Reactive power dispatch or compensation
Single-Line Outage (N-1) Contingencies;	
Transmission line loading <110% Transformer loading: <110% Steady-state voltage range: +/- 10% Transiently stable for 3-phase fault with normal clearing	Line reinforcement Line reinforcement Reactive power dispatch or compensation Generator control fine tuning, reactive power dispatch, Compensation or additional reinforcement
Severe Contingencies	
Transmission line loading: <120% Transformer loading:<120% No voltage collapse No cascaded outages	Automatic load dropping (ALD), generator tripping (GT), Transfer tripping scheme (TTS)
Load Rejection	
Dynamic overvoltage: 30% Peak Volts/Hertz ratio 1.5 p.u./p.u. No self-excitation	Excitation system specification, reactive power
Line Restoration	
Maximum voltage difference: 15% Maximum open-end voltage: 120%	Reactive power compensation

Design Philosophy

With bulk power supply system of National Power Corporation ("*NPC*") still evolving, strict application of the criteria may not be suitable or practical for specific stages in transmission planning. These criteria, coupled with some basic principles, guide TRANSCO in developing the TDP.

The current system design is being driven by the needs of the generators to connect to the system and off-take stations to increase in size due to demand growth.

In an embryonic electricity system, the transmission system will be designed to transport electricity from remote generation sites to the main load centre. (In modern systems where pure "Transmission" is required, this is carried out using HVDC technologies.) In a developed electricity system a transmission "Grid" is established which facilitates connection of generation or demand at any point on the Grid (this is often known as a meshed network where there are multiple paths between nodes on the network). There may be a series of incentives and disincentives to encourage these connections at the most appropriate positions in the grid. A major decision is made when the transmission network (i.e. circuits connecting generation to load centres) is converted to a meshed transmission grid (i.e. providing multiple paths between generation and load centres). This initially occurs when the highest voltage network is of the order of 100kV. Subsequent to this super grid networks are developed to overlay the grid network. Eventually the original grid network (100kV) becomes part of the distribution system.

Currently there are meshed networks formed in the major islands of Luzon and Mindanao but the nature of Visayas has precluded the development of a network and the transmission system remains as a spine in this area. The majority of the 500kV system in Luzon is also a spine network. The full benefit is not being derived from the 500kV network due to the inability of it to be relied upon. The N-1 rule, as applied in this case to a double circuit line, will discount both circuits for a tower failure.

Currently the 230kV and 500kV networks are operated fully interconnected. This means that short circuit current levels on the 230kV switchgear could easily become very high. In order to mitigate against this there will be a design strategy and design standards to be followed.

The N-1 security standard can be left open to various interpretations as illustrated with the 500kV feeder system. With the current state of development within the Philippines we would be better satisfied by a load-related security standard. An illustration of such a standard is shown in Figure 5.1. In this case the security level is related to the size of load. This being an easy to understand and simple to implement system.

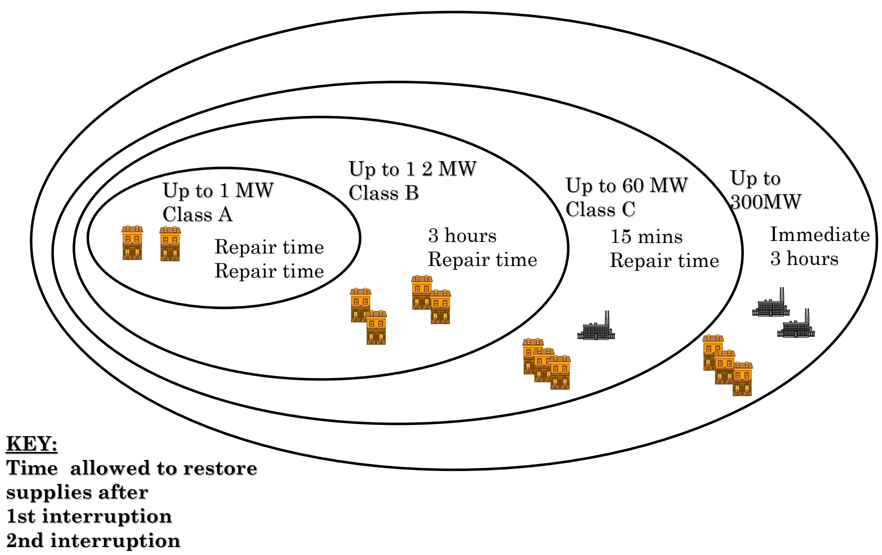


Figure 5.1

Studies show that there is a large under-utilised capacity in the 500kV system linking Northern Luzon with Metro Manila. This is probably due to the parallel paths through the 230kV system being easier to pass through. This is probably being forced to happen due to the strict adherence to the +/- 5% Voltage limits and the insistence of having parallel paths due to the interpretation of the N-1 rule whereby the network must suffer no loss of supply following a double circuit tower line outage. (The North

American NERC Planning Standards indicate that for a double circuit tower line outage there can be planned load shedding and/or generation curtailment.)
There are two options available and studies will be carried out to ensure which is the best option. The first option is to split the 230kV where it creates the parallel paths with the 500kV system. This will provide the added advantage of reducing short circuit levels within the 230kV system. The second option would be to operate this section of the 500kV system at 230kV. There should then be better sharing of the load across these circuits. Studies will be carried out to ensure that this does not have a detrimental effect on short circuit currents. Both of these options should obviate the need for the ongoing project, which is designed to increase the power transfer capacity from the North to Central Luzon.

Measures to Accommodate Growth in Demand

Assessment of Load Profile and Power Delivery

In Luzon, the growth in demand translates to 7.9% average increase during the 11-year period (2002-2012). This is forecast to increase from 5,618 MW level last year to around 13,034 MW by year 2012.

A large portion of the load in Luzon grid is located in the Metro-Manila area while the generation sources are located in the northern and southern parts of the Luzon Island. This year, Luzon is expecting a maximum demand of 6,308 MW with the following load distribution: 56% (3,532 MW) in Metro-Manila, 22.3% (1,407 MW) in northern Luzon and 21.7% (1,369 MW) in southern Luzon. The installed generation capacity in the northern Luzon is 3,852 MW, while southern Luzon has 5,740 MW. In comparison, the transmission corridors to Metro-Manila are limited to power transfer capabilities of 2,300 MW and 4,325 MW for the northern and southern corridors, respectively. Because of this system configuration, it is vital that the transmission backbone be adequate to transfer large amount of power from both the northern and southern areas to Metro-Manila.

A maximum dispatch from the northern plant indicates a maximum transfer of 2,445 MW towards Metro Manila. The transfer limit of the northern corridors is 2,300MW under normal conditions. During an N-1 contingency, however, the transfer limit of the northern corridors will reduce to 2,000 MW. At full dispatch from the southern plants, around 4,371 MW will be available to Metro Manila. The transfer limit of the southern corridors is 4,325 MW towards Metro Manila under normal conditions. During an N-1 contingency, the transfer limit of the southern corridors will reduce to 3,940 MW. This indicates that the supplies to Metro Manila are secure up to 2010 under an N-1 contingency.

In the Visayas grid, the demand for electricity will increase from 893 MW in 2001 to 1,957 MW by 2012, or an average growth of 7.4%. Cebu, Negros and Panay load will grow by 7.2%, Leyte sub-grid at 7.3%, Samar sub-grid at 6.5%, and Bohol sub-grid at 14.7%.

The generation sources comprise geothermal at 945 MW, 160 MW from coal, 301 MW from oil-based plants and 7 MW from hydro plants. Around 640 MW of the geothermal capacity is sourced from Leyte, whilst the rest is generated from the Palimpinon plants in Negros Oriental. Due to large available indigenous capacity in Leyte relative to its local load, Leyte serves as a central generating source for the Visayas grid. At present, Leyte is providing a maximum of 440 MW of geothermal power to Luzon, while 200 MW can be dispatched to Cebu and 40 MW can be transmitted to Bohol. The remaining balance is committed to supply the local load of Leyte-Samar grid. The peak demand in the Visayas is around 846 MW. The bulk of this demand is in Cebu (365 MW) and the rest of the load is distributed as follows: Negros (155 MW), Panay (166 MW), Leyte-Samar (126 MW) and Bohol (34 MW).

To maximise the distribution of the indigenous energy, optimise reserve sharing and minimise energy from oil-based plants, the islands have been interconnected through AC links, the latest of which is the Leyte-Bohol submarine cable link. With the exception of the Leyte-Cebu link, all the interconnection cables are rated 100 MW at 138 kV. The Leyte-Cebu link is rated 200 MW at 230 kV.

In view of the geographic location of the geothermal plants and load distribution, the Visayas grid is optimised to distribute power generally from Leyte-Samar grid to the other islands. Power normally flows from Leyte to Cebu and Leyte to Bohol. Excess power from Cebu is then transmitted to Negros and Panay. However, the power transmission to Bohol is limited to 40 MW since it is presently energised at 69 kV pending the completion of the Leyte-Bohol Stage II Project in 2003.

Power transfer between the islands in the Visayas is inherently limited by the capacity of the submarine cable interconnections. The operational power transfer capability of the submarine cables between Leyte and Cebu is limited to 185 MW, while the Negros-Cebu and Negros-Panay grids are limited to 85 MW. With high demand and negative reserve capacity in Cebu, Negros and Panay, especially during peak condition, the Leyte-Cebu link loading is nearing its thermal limit. Increasing the power transfer to the rated cable capability could lead to system instability during transient disturbance and low voltage in Northern Panay and to the 69 kV load-end substations in Cebu and Negros.

At present, all the existing 138 kV lines in Cebu and Negros are capable of N-1 contingency. However, the 138 kV lines in Panay and Samar are single circuit lines and do not meet the N-1 contingency criteria. Transmission disturbance in one part of the grid can have a major effect on the voltage and frequency of the other sub-grid. This is primarily due long 138 kV and 69 kV radial lines in the system and low localised generation at the far ends of the grid. The grid, therefore, is easily subjected to steady state and voltage instability, especially if the disturbances in the 138 kV lines occur during peak load condition.

Peak demand in Mindanao is currently 954 MW and is projected to increase to 2,041 MW at a compounded growth rate of 7.4% during the period 2002-2012. Since bulk of the base-load generation is dispatched from Lanao, power normally flows from this area to the rest of the grid. Inter-area ties and backbone transmission are at 138 kV level with 69 kV radial lines emanating from the bulk substations to load-end substations. At present, three backbone double circuit lines emanate from Lanao. The double circuit 138 kV lines have a transfer limit of around 370 MW compared to 170 MW for the single circuit line.

At present the Mindanao system is relatively stable in the northern part in terms of voltage and frequency variation even during disturbances but experiences a combination of high and low voltages during off-peak and peak conditions especially in NEMA and SEMA. The high voltages in Bislig, Tindalo and New Loon during off-peak condition is attributed to the long 138 kV lines and limited local generation. However, low voltages are still experienced at the far end of the 69 kV systems during peak condition.

Generation Requirements

The increase in power demand means that there will be additional generation capacity needing to be connected to the grid in the future. The 2002 Power Development Plan prepared by DoE envisioned an additional new capacity of 6, 715 MW during the 10-year planning horizon and about 5,700 MW of this capacity is yet to be identified as to its location. It is imperative that we, TRANSCO, engage in the debate with any developer of generation in order to influence the decision on the best and most appropriate location in the grid network. The expected entry of these future generations and the increase in system demand requires us, TRANSCO, to install the necessary transmission equipment to facilitate the integration of the incoming plants into the system. Regular dialogue with the distribution companies is also necessary to maintain the reliable supply of power to the growing customer demand. The establishment of a reliable and adequate delivery system is mandatory to facilitate effective competition among generating companies and retail supply companies.

Transmission Additions and Reinforcements

Luzon Grid

The Metro Manila area takes the majority of the demand in Luzon. This amounts to 57% i.e. a daily average of peak demand of 3.270MW. The remaining demand is broadly divided equally between Northern and Southern Luzon. Around 55 percent of the generation capacity is sited in Southern Luzon and 45 percent in the North. There is sufficient capacity in the transmission system to cater for the demand of Metro Manila. There is a 500kV transmission backbone running north to south in Luzon. This transmission line is designed to provide flexible operation of the Grid during maintenance and outage conditions.

The Luzon Grid is also connected to the Visayas Grid via a ±350kV HVDC link. This connection is rated at 440MW and is designed to transfer the excess geothermal energy from Leyte (in the Visayas Grid) to Metro Manila. With the growth in IPP's in the South of Luzon and the development of the Visayas Grid to absorb more of the Leyte geothermal energy, the role of this link might change. It has the capability to provide mutual backup to both the Luzon and Visayas grids and as such may mitigate the requirement for the development of the 500kV network in the Tayabas-Naga area.

On-going Projects

Transmission

Within the Luzon grid the major ongoing projects are those associated with the integration of the new power plants into the system. There are also a number of transmission projects designed to strengthen capacity in the North. At least one of these is related to the development of wind farms in the Ilocos region of Luzon. In addition, there are a number of other projects designed to increase substation capacity at a number of substations.

Sub-transmission
There are two major projects in the sub-transmission systems needed to improve reliability and to avoid transformer overloading.

For Implementation Projects

Transmission
There are eleven major projects in this category. There are three projects associated with the 500kV system. One project involves the installation of a switching station on the southern section of the 500kV network. A second project is the utilisation of the switchgear assets at Naga by commissioning the Tayabas-Naga Link. The third project is the development of an additional 500kV link from Labrador in the North to Hermosa.

There are four projects associated with improvements on the 230kV network. A further three projects are associated with reinforcement in the 230kV system. The final project is associated with the replacement of Power Circuit Breakers that are underrated and have operational problems.

Sub-transmission
There are a further three projects in the sub-transmission area all related to improving supplies to the smaller islands.

Indicative Projects

Transmission
There are a number of future projects that are designed to avert transformer overloading and some which are associated with generation projects.

There is one project that is related to creating a 230kV loop in Northern Luzon to improve customer supply security.

Investment profile

The current investment portfolio for Luzon is: -

Table 6.1 Investment portfolio (Thousand Million Pesos)

Year	02	03	04	05	06	07	08	09	10	11
Ongoing	4.1	2.0	2.0	0.1	-	-	-	-	-	-
New	0.2	0.7	3.0	3.8	3.8	6.5	5.1	1.5	5.1	2.4
Total	4.3	2.7	5.0	3.9	3.8	6.5	5.1	1.5	5.1	2.4

There are a number of projects designed to upgrade 230kV circuits between the North and central Luzon. It may be possible to avoid this, as the 500kV circuits in that area are not fully utilised. Plans are in place to establish a 500kV transmission line down to the western side of Luzon. When this is operational there will be two double circuit lines from the North. In this case the 230kV network could be operated as an open ring, which will help utilisation of the circuits (Figure 6.3.1). A further benefit of operating the 230kV system split would be a reduction in fault levels that may allow deferment of some elements of the power circuit breaker replacement programme.

With regard to the strengthening of the southern 230kV circuits, these also have a 500kV network operating in parallel. By proper management this circuit strengthening may not be necessary.

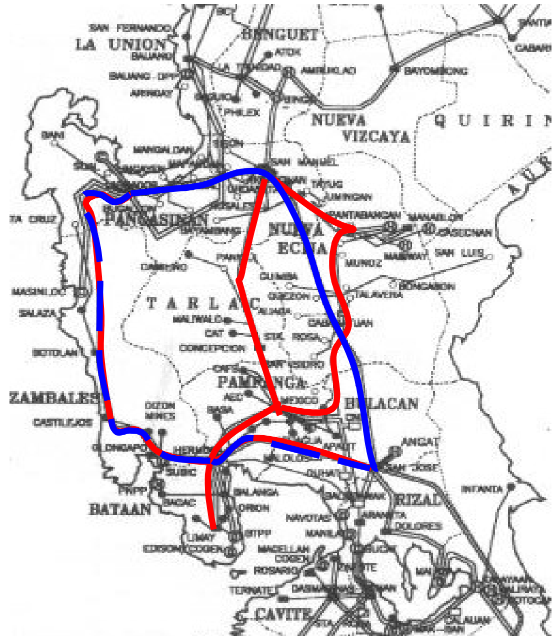


Figure 6.3.1

By making adjustments to the small number of projects mentioned, the following revised expenditure profile can be achieved:

Table 6.2 Revised Program for Luzon (Thousand Million Pesos)

Year	03	04	05	06	07	08	09	10	11
Prior	2.7	5.0	3.9	3.8	6.5	5.1	1.5	5.1	2.4
Revised	2.6	3.1	4.9	5.8	9.7	8.8	4.2	3.1	3.2

Visayas Grid

The Visayas grid is essentially the interconnection of island grids of Cebu, Negros, Panay, Leyte, Samar and Bohol. All these islands have their own power plant except for Samar. There are geothermal power sources in both Leyte and Negros with generation capacities of approximately 750MW and 200MW respectively.

The majority of the geothermal output from Leyte is intended to supply Metro Manila via the 440MW HVDC link to Luzon. A further 200MW link exports part of the remaining generation to main population areas of Cebu. The current peak demand of the Visayas grid is approximately 900MW.

On-going Projects

The ongoing projects in Visayas are in the main related to increasing the transfer capacity of the inter-island links. There are other projects involving the 138kV transmission systems in Panay and Negros.

For Implementation Projects

The main project being considered for implementation is the Cebu-Leyte interconnector designed to add a further 200MW transfer from Leyte geothermal plants to the main population centres on Cebu. There are other small projects associated with improving security within the grid system.

Indicative Projects

The indicative projects proposed consist of a range of smaller projects designed to cater for increased load and higher security of supply.

Investment profile

For its relative size, the Visayas grid consumes a significant proportion of the expenditure on the transmission network.

Table 6.3 Investment portfolio (Thousand Million Pesos)

Year	02	03	04	05	06	07	08	09	10	11
Ongoin g	1.8	4.3	0.9	0.0	0.8	0.2	0.1	0.4	0.4	0.1
New	1.0	2.2	3.4	0.8	-	-	-	-	-	-
Total	2.8	6.5	4.3	0.8	0.8	0.2	0.1	0.4	0.4	0.1

There are a number of island interconnection projects that could be re-phased. The Cebu-Mactan link could be delayed for 12 month but the new Leyte-Cebu interconnection could be tackled in a different way by developing a Bohol-Macatan link to provide an alternative route from Leyte geothermal plant to Cebu City (Figure 6.3.2). Due to higher cost involved with this alternative the original Leyte- Cebu interconnection plan is retained.

The Visayas capacitor projects should be reconsidered following a review of the voltage level standard.

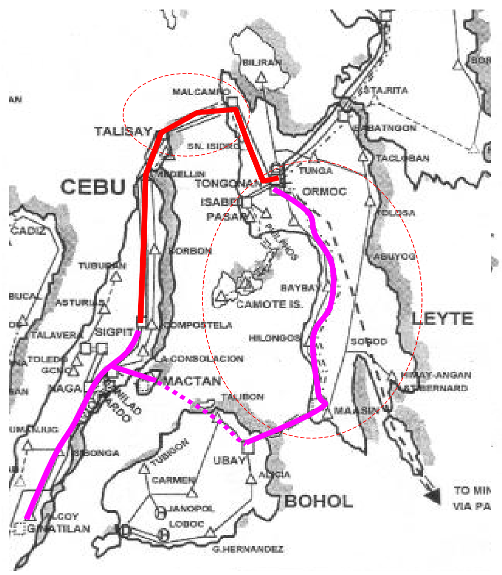


Figure 6.3.2

By making adjustments to a number of projects, the following revised expenditure profile can be achieved:

Table 6.4 Revised Program for Visaya (Thousand Million Pesos)

Year	03	04	05	06	07	08	09	10	11
Prior	6.5	4.3	0.8	0.8	0.2	0.1	0.4	0.4	0.1
Revised	2.6	3.9	2.9	0.6	1.7	1.5	0.8	0.2	0.0

Mindanao Grid

The transmission grid system in Mindanao consists of a network of 138kV and 69kV lines. The current peak demand of 954MW is delivered from the Hydro plants at Angus in Lanas (727MW) and Pulangi (255MW), the geothermal plants at Mount Apo (95MW) and a series of diesel plants (551MW). It is planned to interconnect the Mindanao grid to Visayas via a HVDC link to allow for the Hydro Power to be exported when it is in surplus and to import the geothermal energy from Leyte when the water for the Hydro plant is in short supply.

On-going Projects

The main ongoing projects are on 138kV system to improve the reliability of the supply in the Gen. Santos area. Other projects are designed to accommodate demand growth and supply reliability.

For Implementation Projects

The Mindanao projects for implementation are designed to meet demand growth and improve the supply reliability in some areas. There are two projects designed to improve North to South power capacity on the 138kV network.

Indicative Projects

The indicative projects include the deferred Leyte-Mindanao project and a project to increase the voltage on the North to South interconnector to 230kV. Other projects are to cater for general load growth and reliability improvements.

Investment profile

The current investment profile for Mindanao is:

Table 6.5 Investment Profile (Thousand Million Pesos)

Year	02	03	04	05	06	07	08	09	10	11
Ongoing	0.7	2.1	0.7	0.0	-	-	-	-	-	-
New	2.4	2.8	2.2	2.9	2.2	1.1	2.1	7.2	3.5	1.4
Total	3.2	4.9	2.9	2.9	2.2	1.1	2.1	7.2	3.5	1.4

Some of the major investments in Mindanao are due to subversive or terrorist activity. As a result one particular 138kV double circuit line cannot be relied upon and is not considered to make any contribution to system reliability. There are three projects planned to accommodate this issue and it can be argued with no terrorist activity they would be unnecessary. Alternate ways of addressing these difficulties, such as central government funding, should be sought and the associated projects can therefore be removed from the programme.

The Leyte-Mindanao project is being reassessed in the light of the duties that it is needed to perform.

Other projects such as the small island interconnector projects are being re-phased. By making adjustments to a number of projects, the following revised expenditure profile can be achieved:

Table 6.6 Revised Program for Mindanao (Thousand Million Pesos)

year	03	04	05	06	07	08	09	10	11
prior	4.9	2.9	2.9	2.2	1.1	2.1	7.2	3.5	1.4
Revised	0.6	2.5	1.0	2.1	1.7	2.7	5.6	8.1	5.0

More detailed information on the individual projects that constitute the revised investment program for transmission and sub-transmission can be found in Appendix 1 of this document.

Revenues and Capital Expenditure

Most mature Transmission businesses throughout the world fund their capital expenditure from the revenue that they generate. Typically for these businesses the capital expenditure budget would be approximately 5 or 6 % of the Regulated Asset Base value. This value can be varied depending upon the return on assets allowed under regulation or the value of the X factor in an RPI-X form of regulation. It is essential that the Transmission Business generate sufficient cash to fund a prudent and well-conceived capital investment programme. Failure to provide adequate funding will result in a disjointed and non-optimal implementation of the plan. An estimation of the likely cash generated from rate setting outcomes in the First Control Period suggests that unless the current capital expenditure programme is modified then a cash shortfall will result in 2003.

	2003	2004	2005
Revenue Requirement	21,424	25,210	28,596
Projected Revenue	20,198	22,962	26,155
Shortfall	-1,227	-2,248	-2,441

Table 7.1 Original TDP Revenue shortfall projection

	2003	2004	2005
Revenue Requirement	21,267	24,852	28,421
Projected Revenue	20,198	22,962	26,155
Shortfall	-1,069	-1,890	-2,267

Table 7.2 Revised TDP Revenue shortfall projection

Historical

Transmission system capital expenditure has traditionally been managed in response to external factors such as load growth, connection requests and strengthening weak areas of the network. Whilst the planning horizons appear reasonable the actual achievement usually falls short when judged against planned expenditure. Clearly revenue constraints in the past, delays in obtaining donor funds and problems with "Rights of Way" for transmission circuits have limited the network expenditure and resulted in under investment. Nevertheless, the carry over and deferment of work into subsequent years can easily create a "bow-wave" effect, distorting the forward looking capital investment profile.

Cash flow		**2003**	**2004**	**2005**
Revenue		20,198	22,962	26,155
Franchise tax	2.0%	404	459	523
Local tax	0.5%	101	115	131

Operating expenditure	2,306	2,480	2,842
Capital	17,677	12,492	8,791
Cash	**-290**	**7,417**	**13,868**

Table 7.3 Original TDP capital expenditure – effect on cash flow

It can be seen that there is a small cash negative situation in year one, followed by an increasing cash positive position as the capital expenditure programme falls away. For the reasons described earlier it is unlikely that the expenditure profile will reduce in this manner. The modified investment programme proposed in this report results in a smoother expenditure profile and a cash flow as shown below.

Cashflow		**2003**	**2004**	**2005**
Revenue		20,198	22,962	26,155
Franchise tax	2.0%	404	459	523
Local tax	0.5%	101	115	131
Operating expenditure		2,306	2,480	2,842
Capital		11,827	12,965	13,026
Cash		**5,560**	**6,944**	**9,633**

Table 7.4 Revised capital expenditure – effect on cash flow

Forecast

Work undertaken as part of a project to introduce a new rate setting methodology included a detailed examination of future revenue and associated capital expenditure. Whilst it is uncertain exactly what the revenue for the First Regulatory Period (from 2003 to 2005), will be, a reasonable estimation has been made, as shown in Tables 7.1 and 7.2. Using this estimate together with the component cost elements it is possible to assess what level of capital expenditure can be sustained over that period.

A subsequent estimation of transmission business revenue from 2006 to 2010, which applied a more rigorous incentive based regime, again illustrates the potential funds available to finance a capital expenditure programme.

Applying these estimates, the investments detailed in the current TDP planning horizon can be tested to ensure that adequate revenue is available to fund them within the constraints applied. It should be stressed that a great deal of uncertainty surrounds the medium and long term investments in the TDP and the composition and phasing of this element of the programme will undoubtedly change.

Integrated Investment Plan

Prioritised Projects

Previous sections describe the composition and phasing of specific elements in the portfolio of TDP projects on a grid basis. Amendments introduced since the last TDP result in an adjustment to both the prioritisation of implementation and the associated investment requirements.

Overall profile for next 10 years

The overall investment profile for the next 10 years has been modified and is shown in Fig 8.1.

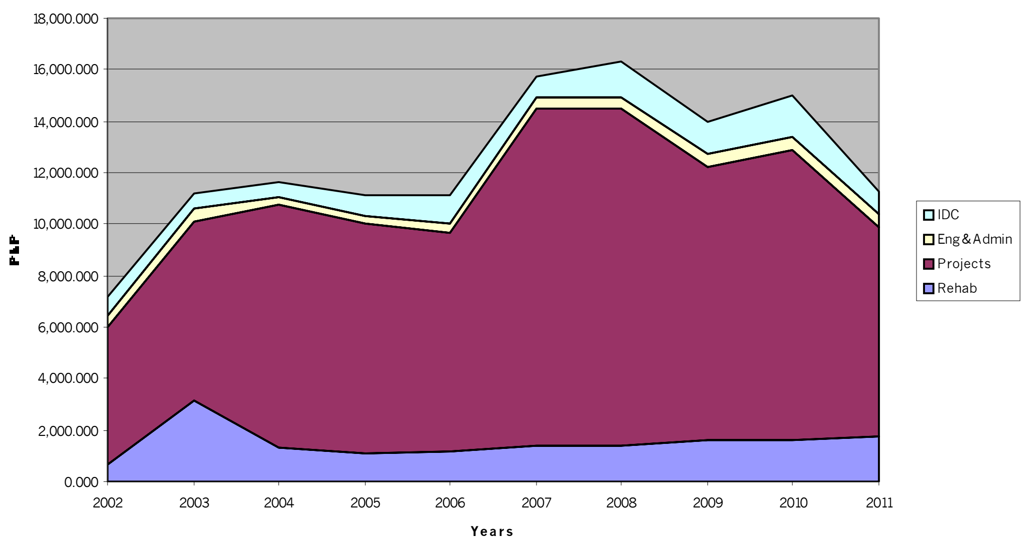


Figure 8.1

It can be seen that there is an acceleration of investment around 2006, where the more detailed short term planning horizon ends, followed by a decline in the longer term. In reality these apparent step changes are unlikely to occur and the transition will be smoother as project deferments and new initiatives are amended in the next few years. One of the main objectives of this revision of the TDP was to smooth the expenditure profile in the years 2003 to 2005. Fig 8.2 shows that the previous steep decline in expenditure across this period has been substantially eliminated and the resulting profile is much flatter.

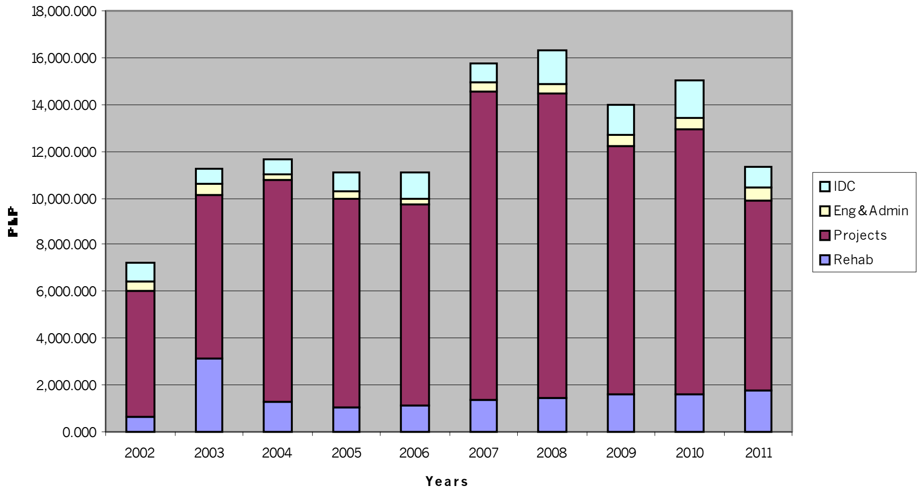


Figure 8.2 First Period Revised Capex

The profile of Fig 8.2, is much more uniform across the period 2003-05, showing a slight rise in 2004 and reducing in 2005. This does not impact considerably on the revenue shortfall, due to the mechanism by which a return is generated from capital expenditure added to the rate-base. However, it has a marked effect on cashflow.

Uncertainty in Medium and Long Term

The shape of the overall profile in Fig 8.1 reinforces the uncertainty in the medium and long-term expenditure forecasts. The majority of the projects in this category are generic, with the exception of the Leyte-Mindanao interconnector. This project, due to its considerable expenditure, distorts the profile in the years 2009 and 2010.

Determining the revenue requirements

The revenue requirement for the Transmission Business in the period 2003 to 2005, based on the initial TDP investment program, is shown in Table 7.1. This predicts a revenue shortfall over the First Regulatory Period of the new regulatory regime. A re-calculation using the revised program, shown in Table 7.2, does not significantly change this situation. In order to do so would require a major reduction in capital expenditure, which is not consistent with the aims and objectives of TRANSCO or a concessionaire.

However, when cashflow is considered then the revised investment program does produce the desired effect, namely a positive cash position throughout the First Regulatory Period as Tables 7.3 and 7.4 illustrate. As a degree of uncertainty always surrounds forecast capital expenditure, it can be seen that the revised cashflow has a reasonable margin to accommodate program changes whilst remaining cash positive.

APPENDIX A

“Measure to Improve Performance”

Performance Indicators

A number of transmission network performance indicators are cited in the Implementing Rules and Regulations to the EPIRA ("*IRR*"). Many of the indicators appear internationally recognised and should aid comparison with other transmission network operators. A summary of some of the indicators is given below:

- The "sustained average interruption frequency index" is calculated as follows:

  SAIFI = Connected MVA impacted by outages $>$ 10 minutes $\div$ Total connected MVA for the system considered;

- The "momentary average interruption frequency index" is calculated as follows:

  MAIFI = Connected MVA impacted by outages $\leq$ 10 minutes $\div$ Total connected MVA for the system considered;

- The "sustained average interruption duration index" is calculated as follows:

  SAIDI = Σ (Outage MVA x minutes) $\div$ Total connected MVA for Area;

- The "system interruption severity index" is calculated as follows:

  SISI = Σ Unserved energy (MW lost x duration in minutes) $\div$ System peak load in MW.

Note: - "Interruption" means the loss of service to a customer or a group of customers or other facilities.

It is noted that certain definitions, particularly those of SAIDI, SAIFI and MAIFI, depart from those applied internationally, in terms of the periods over which they apply. These are to be reviewed and an agreed set of performance standards is to be published by the ERC as part of the adoption of a new rate setting methodology.

All the necessary data for monitoring performance is not collected for all three grids at the present time. The methodologies applied and accuracy achieved in collecting this performance data is to be reviewed and amended so that the data produced is consistent and accurate across all three grids.

Initially we shall set targets based upon the performance of comparable countries and with a year on year improvement element. We also intend providing separate reports for inter-island tie availability with particular emphasis on generation curtailment and load shedding.

We will request the ERC to define under what circumstances it would grant an excluded period of performance for example during unusually extreme storms.

The historical values of performance are summarised below.

TABLE 3.1
Historical values of performance indicators transmission

PERFORMANCE INDICATORS	LUZON*					VISAY AS			MWID AM AD				
	1993	1999	2000	2901	AVE	2000	2001	AVE	1993	1999	2000	2001	AVE.
Number of interruption Events	270	192	301	400	291	203	339	271	164	147	275	136	181
Sustained Average Interruption Frequency Index (SAFI)	1.99	0.72	124	1.37	1.02	2.08	3.94	2.93	2,73	2.49	5.69	1.99	3.15
Momentary Average Interruption Frequency Index (MAIFI)	0.53	0.28	0.22	0.17	0.22	1.12	1J2	1,30	1.50	1.00	0.91	0.93	1.05
Sustained Average Interruption Duration index (SAIDI) (minutes)	739.45	147.56	392.29	564.81	352.09	350.42	681.47	512.06	308,63	4,705	1,602	555	1,730
System Interruption Severity Index (SISI) (minutes)	6.02	9.65	15.42	10.52	9.73	212.27	612.49	408.08	43.47	21,13	51.03	16,63	31.77
Frequency of Tripping per cct. km, (FOT) (trip/100cct-km)	13	12	14	15	13	17	10	14	15	15	21	13	15
Average Outage Duration (AOD) (min/trip)	183.07	571.77	265.38	369.13	344.31	150.34	159.14	172A 1	170.20	539.22	373A9	327.07	357.33
Accumulated Time Error (ATE)	111	37	1	7	39								
Frequency Limit Violation (FLV)	126	32	3	14	44								
Voltage Limit Violation (VLV)	212	37	9	14	111								

Note: Exemptions are 0001,0008, 0012, 0014, 0016 as per meeting on July 3,2002.
* 4 years average based on SPMIS
* 2 years *yarn: based on SPMIS

APPENDIX B

Capital Expenditure

2002 to 2011

Capital Expenditure

The following tables show the transmission and sub-transmission capital expenditure by grid and by project class. Generation associated projects are also included for completeness, but no forecast costs are available. Summary tables at the end of this appendix provide a breakdown of all capital expenditure, including central and non-project related costs. Unless otherwise stated all expenditure is millions of Philippine Peso's and in 2002 prices.

Note: The "new" projects listed here are the combined "for implementation" and "indicative" projects referred to in the main document.

A.1 Luzon

A.1.1 On-going

	Proj No		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Calaca II Asso. T/L	**LUT96B0 0**	**T**	0.608	15.000	90.000	25.000	5.000	0.000	0.000	0.000	0.000	0.000
Sucat-Sta. Mesa-Balintawak 230 KV T/L	**LUT95B0 0**	**T**	18.405	29.000	68.000	21.000	10.000	0.000	0.000	0.000	0.000	0.000
Pagbilao Coal T/L	**LUT96E0 0**	**T**	100.729	108.103	22.000	25.500	5.500	0.000	0.000	0.000	0.000	0.000
Leyte-Luzon HVAC Interc. Project	**LIT97D0 0**	**T**	0.000	18.111	7.800	4.000	2.000	0.000	0.000	0.000	0.000	0.000
Rehab of Naga-Tayabas 500 KV EHV	**LUT97D0 3**	**T**	0.000	18.250	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Northwestern EHV(Labrador-	**LUT97F0 0**	**T**	0.000	60.099	29.400	14.400	13.200	0.000	0.000	0.000	0.000	0.000
Relocation of Lahar-Affected T/L	**LUP00A0 0**	**T**	76.833	23.473	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

NGAS Asso. TL	**LUT02A00**	**T**	651.602	604.523	3.147	0.061	0.061	0.000	0.000	0.000	0.000	0.000
Casecnan (Manablon) Hydro Asso. TL	**LUT99C00**	**T**	6.485	43.553	10.615	6.275	6.275	0.000	0.000	0.000	0.000	0.000
WB-TGRL-LUZON S/S REINF. PROJ.	**LUS96F00**	**T**	132.999	160.089	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Luzon Cluster "C" S/S Exp Project	**LUS99A00**	**T**	0.051	11.757	17.402	1.000	0.000	0.000	0.000	0.000	0.000	0.000
Batangas Trans. Reinf. Proj.	**LUT00C00**	**T**	1,141.367	778.373	947.135	66.395	40.445	0.000	0.000	0.000	0.000	0.000
Bauang-San Esteban L2 Stringing Project	**LUT01A00**	**T**	1.670	138.837	228.316	9.851	4.694	0.000	0.000	0.000	0.000	0.000
Binga-San Manuel 230kV TL Project	**LUT02D00**	**T**	3.604	18.103	16.110	9.400	7.000	0.000	0.000	0.000	0.000	0.000
			2,134.353	**2,027.271**	**1,440.924**	**182.880**	**94.174**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Balayan-Calatagan 69 KV	**LUS96Z00**	**ST**	0.430	1.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
T/L & S/S Proj-1 & 2 (EDCF)	**LUS97H00**	**ST**	1.964	230.265	37.938	78.357	3.400	0.000	0.000	0.000	0.000	0.000
Luzon(North) Subtransmission Project-1&2	**LUS99C00**	**ST**	85.399	50.011	53.328	41.287	65.287	0.000	0.000	0.000	0.000	0.000
			87.793	**281.277**	**91.766**	**120.144**	**68.687**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Bakun Hydro T/L	**LUT00A00**	**A**	**98.997**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

A.1.2 New

	Proj No		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Biñan-Dasmariñas T/L Upgrading	**LUT04C00**	**T**	0.000	154.613	129.837	17.523	8.649	0.000	0.000	0.000	0.000	0.000
Alaminos 500KV Switching Stn	**LUS04B00**	**T**	0.000	31.502	126.062	1,019.693	747.511	0.000	0.000	0.000	0.000	0.000
Luzon(North) T/L Upgrading Proj-2	**LUT03D00**	**T**	0.000	25.443	850.345	1,610.446	3,365.429	3,456.023	0.000	0.000	0.000	0.000
Kalayaan-Makban Upgrdg Project	**LUT05C00**	**T**	0.000	4.607	94.736	1,181.673	361.782	0.000	0.000	0.000	0.000	0.000
San Esteban-Bantay-Laoag 230 KV	**LUT02E00**	**T**	2.022	35.188	142.424	583.291	369.308	0.000	0.000	0.000	0.000	0.000
Luzon Substation Expn Projects -1	**LUS05A00**	**T**	0.000	0.000	0.000	85.660	626.880	184.822	0.000	0.000	0.000	0.000
New Munoz 230 KV Substation	**LUS06B00**	**T**	0.000	0.000	0.000	6.200	21.200	221.235	0.000	0.000	0.000	0.000
Luzon Substation Expn Projects 2	**LUS07A00**	**T**	0.000	0.000	0.000	0.000	6.200	603.544	620.826	0.000	0.000	0.000
Luzon Substation Expn Projects 3	**LUS08A00**	**T**	0.000	0.000	0.000	0.000	0.000	992.347	1,020.923	0.000	0.000	0.000
TL Hermosa-Mexico-Balwk Upgrad	**LUT05A00**	**T**	0.000	0.000	0.000	0.000	0.000	729.284	1,502.735	774.222	0.000	0.000
Luzon S/S Expn. Proj. - 4	**LUS09A00**	**T**	0.000	0.000	0.000	0.000	0.000	249.596	513.568	264.207	0.000	0.000
BTPP Repowering (600MW)	**LUT04A00**	**T**	0.000	0.000	0.000	0.000	0.000	201.448	415.019	213.781	0.000	0.000

1200MW @ Masinloc T/L Project	**LUT09A00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	1,280.420	1,317.420	1,355.637	1,395.117
600MW @ Tayabas Upgrading Proj	**LUT09B00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	448.859	461.835	475.238	489.084
Northern Luzon 230KV T/L Loop Proj	**LUT10H00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	844.056	870.327	897.544	925.747
Luzon Substation Expansion Proj-5	**LUS11A00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	324.617	334.001	343.694	353.707
Masinloc Bus-in Labra-Boto-Olong		**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			2.022	**251.353**	**1,343.403**	**4,504.485**	**5,506.959**	**6,638.299**	**6,971.022**	**4,235.792**	**3,072.112**	**3,163.655**
SLRC Sub-Transmission Project- 1	**LUS99D00**	**ST**	41.846	27.844	146.401	44.792	23.992	0.000	0.000	0.000	0.000	0.000
SLRC Sub-Transmission Project- 2	**LUS99F00**	**ST**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Luzon Subtransmission Project	**LUS04B00**	**ST**	0.000	5.276	39.850	23.100	0.350	1,218.870	0.000	0.000	0.000	0.000
Luzon-Catanduanes Island Int. Proj	**LUS06C00**	**ST**	0.000	0.000	2.400	24.400	29.400	484.279	495.925	0.000	0.000	0.000
Luzon-Marinduque Island Int. Proj	**LUS06D00**	**ST**	0.000	0.000	2.400	16.400	19.400	491.694	503.648	0.000	0.000	0.000
Luzon-Mindoro Island Int. Project	**LUS06E00**	**ST**	0.000	0.000	4.750	17.100	18.750	803.685	823.615	0.000	0.000	0.000
Tuguegarao-Solana 69 KV Line	**LUS97H05**	**ST**	0.000	0.000	0.000	0.000	0.000	17.400	17.992	0.000	0.000	0.000
			41.846	**33.120**	**195.801**	**125.792**	**91.892**	**3,015.927**	**1,841.180**	**0.000**	**0.000**	**0.000**
300-MW Base Plt @ Isabela Ass	**LUT06A**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

T/L	**00**											
360MW Agbulu Hydro Asso. T/L	**LUT08C00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
60MW Abuan Hydro Asso. T/L	**LUT06B00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
46MW Addalam Hydro Asso. T/L	**LUT07C00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
113MW Kanan Hydro Asso. T/L	**LUT07A00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
320MW Batangas Private Pwr AssoT/L		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
600MW @ PNPP Asso T/L Project		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
175MW Binongan Hydro Asso T/L		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3x460MW LNG @ Batangas Asso. T/L	**LUT09C00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
332MW Diduyon Hydro Asso T/L		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

A.2 **Visayas**

A.2.1 On-going

	Proj No		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Leyte-Cebu HVAC Interc./Repair	**VIT96A00**	**T**	400.818	82.750	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cebu III 138kV Trans. Proj	**VIT98B00**	**T**	45.550	65.952	64.700	14.200	5.700	0.000	0.000	0.000	0.000	0.000
Basak S/S Expansion	**VIT98C00**	**T**	0.000	10.969	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cebu IV 138 KV T/L	**VIT98C00**	**T**	2.985	7.600	10.000	4.000	0.000	0.000	0.000	0.000	0.000	0.000
Leyte-Bohol Interconnection (I & II)	**VIT00A00**	**T**	207.281	725.170	102.884	25.534	7.334	0.000	0.000	0.000	0.000	0.000
Panay IV 138kV Transmission Proj	**VIT96B00**	**T**	58.846	55.434	31.400	15.000	15.000	0.000	0.000	0.000	0.000	0.000
Negros III 138/69/13.8 KV T/L	**VIS98A00**	**T**	13.491	203.337	43.000	6.000	1.940	0.000	0.000	0.000	0.000	0.000
Negros IV 138 KV T/L	**VIT98A00**	**T**	18.457	52.580	58.100	13.924	12.924	0.000	0.000	0.000	0.000	0.000
Leyte-Samar Reinforcement	**VIT99B00**	**T**	145.399	210.423	30.065	5.715	5.715	0.000	0.000	0.000	0.000	0.000
Visayas S/S Expansion Projects	**VIS99C00**	**T**	0.200	1.666	0.283	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cebu-Mactan Interconnection Project	**VIT00C00**	**T**	2.964	331.146	1,293.137	582.761	15.137	0.000	0.000	0.000	0.000	0.000
			895.99	**1,747.02**	**1,634.56**	**667.13**	**63.749**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

			1	**7**	**8**	**3**						
Visayas Capacitor Proj. I	**VIS97A00**	**ST**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Visayas Capacitor Proj. II	**VIS99B00**	**ST**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Negros V Transmission Project	**VIS00B00**	**ST**	0.000	4.075	89.597	169.418	25.946	0.000	0.000	0.000	0.000	0.000
			0.000	**4.075**	**89.597**	**169.418**	**25.946**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

A.2.2New

	Proj No		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Leyte-Cebu Exp/Uprating Project	**VIT00B00**	**T**	5.922	839.004	1,606.288	631.912	3.874	0.000	0.000	0.000	0.000	0.000
Northern Panay Backbone Project	**VIT05A00**	**T**	2.250	1.315	156.855	485.600	192.400	0.000	0.000	0.000	0.000	0.000
Southern Panay Backbone	**VIT05D00**	**T**	0.000	0.000	102.400	362.400	114.400	0.000	0.000	0.000	0.000	0.000
Vis. Substation Expansion-2006	**VIS05B00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Visayas 69KV Projects	**VIS95A00**	**T**	0.000	0.000	2.400	8.400	10.400	0.000	0.000	0.000	0.000	0.000
Ginatilan Project (New)	**VIT07C00**	**T**	0.000	0.000	0.000	0.000	0.000	136.743	140.788	0.000	0.000	0.000
Bohol Backbone Project	**VIT07D00**	**T**	0.000	0.000	2.400	8.400	10.400	251.621	259.143	0.000	0.000	0.000
Visayas PCB Replacement Project	**VIT07D00**	**T**	0.000	0.000	4.419	35.992	4.499	0.000	0.000	0.000	0.000	0.000
Visayas S/S Expansion Project-2007	**VIS07A00**	**T**	0.000	0.000	0.000	0.000	0.000	152.605	157.000	0.000	0.000	0.000
Visayas S/S Expansion Project-2008	**VIS07A00**	**T**	0.000	0.000	0.000	0.000	0.000	223.805	460.500	236.906	0.000	0.000
Visayas S/S Expansion Project-2009	**VIS09A00**	**T**	0.000	0.000	0.000	0.000	0.000	148.815	306.201	157.526	0.000	0.000
Visayas S/S Expansion Project-2010	**VIS10A00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	192.431	395.987	203.739	0.000
Visayas S/S Expansion Project-	**VIS11A0**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

2011	**0**											
Visayas S/S Expansion Project-2012	**VIS12A00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Negros-Cebu Interconnection Exp.	**Deleted**		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			8.172	**840.320**	**1,874.763**	**1,532.704**	**335.973**	**913.589**	**1,516.062**	**790.419**	**203.739**	**0.000**
Visayas Sub-transmission Projects I	**VIS03C00**	**ST**	32.860	45.486	219.795	537.078	168.616	0.000	0.000	0.000	0.000	0.000
Boracay Elec. Project	**VIS02B00**	**ST**	0.000	0.000	10.000	8.790	0.000	0.000	0.000	0.000	0.000	0.000
Small Island Grid Intercon. Proj	**VIS06A00**	**ST**	0.000	0.000	2.400	9.400	10.400	800.745	0.000	0.000	0.000	0.000
Western Panay 69 KV TL (EXPN)	**Deleted**	**S**	0.000	10.536	22.500	17.400	8.200	0.000	0.000	0.000	0.000	0.000
			32.860	**56.022**	**254.695**	**572.668**	**187.216**	**800.745**	**0.000**	**0.000**	**0.000**	**0.000**
Bronzeoak Asso. T/L (48.2 MW)	**VIT04E00**	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cebu Peak Asso T/L (2x50MW) 06-07		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bohol Diesel Asso T/L (20MW)		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Negros Peaking Asso T/L (30MW)		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cebu Mid Asso T/L (2x50MW) 06-10		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Bohol Mid Asso T/L (2x10 & 1x20MW)		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Cebu Peaking Asso T/L (2x60MW) 08-09	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Panay Midrange Asso T/L (50MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Bohol Midrange Asso T/L (30MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Cebu Peaking Asso T/L (2x60MW) 10-11	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Panay Peaking Asso T/L (60MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Negros Peak Asso T/L (2x60MW) 10-11	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Cebu Baseload Asso T/L (100MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Cebu Mid Asso T/L (100MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000
Panay Peaking Asso T/L (30MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0000.000

A.3 Mindanao

A.3.1 On-going

	Proj No	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Mindanao Geothermal Asso. 138KV	MIT97D00 T	0.004	0.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Davao-Tindalo 138kV T/L	MIT97A00 T	0.968	0.600	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao S/S Expansion	MIS97E00 T	283.050	29.391	6.508	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao S/S Exp-1999	MIS99A00 T	161.032	3.888	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Maco S/S-New	MIS99B00 T	0.968	11.500	62.420	10.000	0.000	0.000	0.000	0.000	0.000	0.000
Bunawan S/S(new)	MIS97H00 T	1.131	21.600	55.000	5.000	5.000	0.000	0.000	0.000	0.000	0.000
Nuling Expansion	MIS97K00 T	0.000	0.500	8.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Zamboanga City Area 138 KV T/L	MIT00B00 T	2.794	219.086	280.412	13.883	14.957	0.000	0.000	0.000	0.000	0.000
Gen. Santos-Tacurong Line Reinf.	MIT00D00 T	3.186	17.424	583.408	170.936	0.210	0.000	0.000	0.000	0.000	0.000
Tacurong-Nuling TL	MIT00G00 T	3.838	12.791	406.315	97.180	92.000	0.000	0.000	0.000	0.000	0.000
		456.971	**317.280**	**1,402.563**	**296.999**	**112.167**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Mindanao 69kV T/L Project-2	MIS97G00 ST	13.651	37.673	15.038	6.089	12.323	0.000	0.000	0.000	0.000	0.000
Mindanao Capacitor Proj. I & II	MIS97J00 ST	92.254	20.860	3.000	2.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Capacitor Proj. III	MIS00B00 ST	0.000	2.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		105.905	**60.533**	**18.038**	**8.089**	**12.323**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

A.3.2 New

	Proj No		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Kabacan Switching & 138 KV TL	**MIT00C00**	**T**	0.776	13.206	379.677	78.453	71.621	0.000	0.000	0.000	0.000	0.000
Aurora-Dipolog (138kV TL	**MIT03B00**	**T**	6.213	31.075	371.846	91.850	0.000	0.000	0.000	0.000	0.000	0.000
Eastern Mindanao Reinf. Project	**MIT05C00**	**T**	1.646	17.297	40.449	172.841	987.984	0.000	0.000	0.000	0.000	0.000
Mindanao S/S Expansion - 2005	**MIS04A00**	**T**	0.000	2.500	0.000	70.852	550.816	0.000	0.000	0.000	0.000	0.000
Mindanao S/S Shunt Reactor	**Deleted**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MIind PCB Replacement Project	**MIS04B00**	**T**	0.000	0.866	8.899	56.152	7.019	0.000	0.000	0.000	0.000	0.000
Maasin Substation (New)	**MIT05B00**	**T**	0.000	0.000	0.000	0.000	44.900	610.051	0.000	0.000	0.000	0.000
Mind Substation Expansion-2007	**MIS07C00**	**T**	0.000	0.000	0.000	0.000	39.846	499.127	0.000	0.000	0.000	0.000
Aurora-Abaga Reinf Project	**MIT07D00**	**T**	0.000	0.000	1.200	12.400	64.830	336.945	0.000	0.000	0.000	0.000
Mind Substation Expansion-2008	**MIS08B00**	**T**	0.000	0.000	0.000	0.000	0.000	66.874	137.600	70.789	0.000	0.000
Matanao-Klinan Reinforcement	**MIT08D00**	**T**	0.000	0.000	0.000	1.200	7.400	85.431	176.242	90.909	0.000	0.000
Mind Substation Expansion-2009	**MIS09B00**	**T**	0.000	0.000	0.000	0.000	0.000	51.157	105.417	54.315	0.000	0.000
Mind Substation Expansion-	**MIS10B00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	34.318	70.621	36.335	0.000

2010												
Malaybalay S/S (New)	**MIT10C00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	85.061	175.204	90.230	0.000
Aurora-Nuling TL	**MIT10D00**	**T**	0.000	0.000	0.000	0.000	0.000	92.555	381.963	394.137	101.690	0.000
Mind Substation Expansion-2012	**MIS10B00**	**T**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	115.485	118.837	30.575
Leyte-Mindanao Int. & 138 KV	**MIT00E00**	**T**	140.090	44.114	81.087	111.087	81.087	0.000	1,816.390	4,676.113	7,705.387	4,960.420
			148.725	**109.058**	**883.158**	**594.836**	**1,855.503**	**1,742.141**	**2,736.992**	**5,647.574**	**8,052.480**	**4,990.995**
Region 9 Subtrans Project	**MIS03A00**	**ST**	4.022	14.201	23.454	24.794	18.594	0.000	0.000	0.000	0.000	0.000
Region 10 Subtrans Project	**MIS03B00**	**ST**	7.002	41.943	58.895	24.292	26.436	0.000	0.000	0.000	0.000	0.000
Region 11 Subtrans Proj.	**MIS03C00**	**ST**	3.789	21.847	25.698	14.948	11.498	0.000	0.000	0.000	0.000	0.000
Region 12 Subtrans Proj.	**MIS03D00**	**ST**	0.000	32.994	57.411	31.001	73.451	0.000	0.000	0.000	0.000	0.000
ARMM Subtrans Project	**MIS03E00**	**ST**	0.000	6.689	6.704	6.164	7.454	0.000	0.000	0.000	0.000	0.000
Small Island Intercon. Project	**MIS04C00**	**ST**	0.000	0.000	4.950	20.300	27.950	0.000	0.000	0.000	0.000	0.000
Damilag 69KV S/S Project	**Deleted**	**S**	0.340	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			15.153	**117.673**	**177.113**	**121.500**	**165.384**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
Mindanao Mid Asso T/L (150MW)		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Mid Asso T/L		**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

(150MW)											
Mindanao Peak Asso T/L (2x30MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Mid Asso T/L (150MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Mid Asso T/L (300MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Base Asso T/L (100MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Mindanao Peak Asso T/L (90MW)	**A**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

A.4 **Summary**

The following tables summarise the TRANSCO Capital Expenditure from 2002 to 2011

A.4.1 Rehabilitation, Expansion & Improvement

TRANSMISSION LINES REHABILITATION	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
UTILITY OPERATIONS	**579.820**	**986.199**	**710.303**	**705.542**	**810.439**	**941.909**	**929.868**	**1,068.864**	**1,024.290**	**1,134.367**
Other Improvement/Expansion	267.159	573.542	275.266	247.371	441.070	417.095	386.891	493.551	381.602	400.204
Utility Operations	180.019	316.187	276.739	287.654	205.555	285.074	285.488	300.376	323.534	364.356
RIGHT OF WAY	132.642	96.470	158.298	170.518	163.814	239.740	257.490	274.937	319.155	369.808
HEAD OFFICE/SYSTEM OPS/	**97.640**	**2,172.522**	**583.238**	**371.625**	**331.685**	**460.831**	**481.758**	**506.622**	**561.150**	**621.575**
HEAD OFFICE	29.641	393.995	313.254	103.714	110.800	151.958	164.802	183.285	203.826	226.686
SYSTEM OPERATIONS	67.957	235.708	243.203	240.419	220.885	308.874	316.956	323.337	357.323	394.890
WESM PROJECT	0.042	1,542.819	26.781	27.491	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL REHABILITATION	**677.460**	**3,158.721**	**1,293.541**	**1,077.167**	**1,142.124**	**1,402.741**	**1,411.627**	**1,575.486**	**1,585.440**	**1,755.943**

A.4.2 Projects

PROJECTS		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Transmission											
Luzon	**On-**	2,233.35	2,027.27	1,440.92	182.880	94.174	0.000	0.000	0.000	0.000	0.000
	New	2.022	251.353	1,343.40	4,504.48	5,506.95	6,638.29	6,971.02	4,235.79	3,072.11	3,163.65
Visayas	**On-**	895.991	1,747.02	1,634.56	667.133	63.749	0.000	0.000	0.000	0.000	0.000
	New	8.172	840.320	1,874.76	1,532.70	335.973	913.589	1,516.06	790.419	203.739	0.000
Mindanao	**On-**	456.971	317.280	1,402.56	296.999	112.167	0.000	0.000	0.000	0.000	0.000
	New	148.725	109.058	883.158	594.836	1,855.50	1,742.14	2,736.99	5,647.57	8,052.48	4,990.99
	On-	**3,586.31**	**4,091.57**	**4,478.05**	**1,147.01**	**270.090**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
	New	**158.919**	**1,200.73**	**4,101.32**	**6,632.02**	**7,698.43**	**9,294.02**	**11,224.0**	**10,673.7**	**11,328.3**	**8,154.65**
Sub-											
Luzon	**On-**	87.793	281.277	91.766	120.144	68.687	0.000	0.000	0.000	0.000	0.000
	New	41.846	33.120	195.801	125.792	91.892	3,015.92	1,841.18	0.000	0.000	0.000
Visayas	**On-**	0.000	4.075	89.597	169.418	25.946	0.000	0.000	0.000	0.000	0.000
	New	32.860	56.022	254.695	572.668	187.216	800.745	0.000	0.000	0.000	0.000
Mindanao	**On-**	105.905	60.533	18.038	8.089	12.323	0.000	0.000	0.000	0.000	0.000
	New	15.153	117.673	177.113	121.500	165.384	0.000	0.000	0.000	0.000	0.000
	On-	**193.698**	**345.884**	**199.401**	**297.651**	**106.956**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
	New	**89.859**	**206.815**	**627.609**	**819.960**	**444.492**	**3,816.67**	**1,841.18**	**0.000**	**0.000**	**0.000**
Other Projects		1,322.05	1,089.30	30.778	22.949	22.213	0.000	0.000	0.000	0.000	0.000
TOTAL PROJECTS		**5,350.838**	**6,934.315**	**9,437.168**	**8,919.597**	**8,542.186**	**13,110.700**	**13,065.256**	**10,673.785**	**11,328.331**	**8,154.650**

A.4.3 Warehousing, Engineering and Administration & IDC

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
A. Engineering Resource Services	94.873	123.266	123.266	123.266	123.266	164.160	172.778	181.849	191.396	201.444
B. Engineering Administration	284.618	404.955	182.237	182.237	182.237	242.693	255.435	268.845	282.959	297.815
ENGINEERING & ADMINISTRATION	**379.490**	**528.222**	**305.503**	**305.503**	**305.503**	**406.853**	**428.213**	**450.694**	**474.356**	**499.259**
INTEREST DURING CONSTRUCTION	**792.860**	**591.211**	**617.666**	**793.584**	**1,121.528**	**843.077**	**1,385.775**	**1,257.662**	**1,619.639**	**894.353**

A.4.4 Overall Expenditure

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	7,200.649	**11,212.469**	**11,653.878**	**11,095.852**	**11,111.341**	**15,763.371**	**16,290.871**	**13,957.627**	**15,007.765**	**11,304.205**
in 2001 prices	**6805.9062**	**10597.7968**	**11015.00753**	**10487.5725**	**10502.2129**	**14899.2163**	**15397.7986**	**13192.4644**	**14185.03315**	**10684.5033**

Cumulative 2002 prices	**124,598.027**
Cumulative 2001	**117,767.51**

prices	**2**